Chapter Two

A Case Study of California Offshore Petroleum Production, Well Stimulation, and Associated Environmental Impacts

James Houseworth, William Stringfellow[1]

[1]Lawrence Berkeley National Laboratory, Berkeley, CA

2.1. Abstract

This case study summarizes current practices concerning the use of well stimulation and associated potential environmental impacts for California offshore petroleum-production operations. It includes an assessment of the discharges and emissions of contaminants and their potential environmental impacts. Well stimulation includes hydraulic fracturing (with proppant or acid) and matrix acidizing as presented in Volume I, Chapter 2. The case study describes current offshore oil and gas production facilities, including the geologic and petrophysical characteristics of the oil and gas reservoirs under production, and the available information on fluid handling and ultimate disposition of stimulation flowback fluids as ocean discharge or injection into the producing or waste disposal zones. This case study also provides an explanation of the current regulatory limits on ocean discharge of stimulation flowback fluid and comingled produced water under the National Pollutant Discharge Elimination System, as well as a review of existing information on discharge volumes and characteristics. In addition, an assessment of offshore air emissions, including criteria pollutants, toxic pollutants, and greenhouse gases, is included.

Volume I presents the level of well stimulation activity for offshore California. Of the 109 wells per month on average undergoing hydraulic fracturing in California, about 1.5 per month were in state waters. Hydraulic fracturing in federal waters occurs even less frequently, at about 1 per year (Volume I, Chapter 3). Offshore acid treatments appear to be used more frequently than hydraulic fracturing in state and federal waters, but the levels of activity are difficult to quantify from the available records. There are no records of acid fracturing conducted offshore.

Studies of produced water discharge into the marine environment have shown that there may be adverse impacts, particularly for reproductive behavior and larval development of some species. However, site-specific studies of fish populations around offshore facilities indicate that rockfish species reached high densities around offshore oil and gas facilities. While some level of adverse impacts are likely as a result of wastewater discharge in general (including well stimulation fluids), the available data on fish species inhabiting platforms indicates that any negative impacts of discharge are relatively minor given that population growth rates in the vicinity are very high.

Criteria pollutants emitted by offshore oil and gas production facilities represent a small fraction of total emissions in the associated air basins. Only a small fraction of these offshore oil production emissions can be attributed to well stimulation. Toxic air emissions from the facilities in federal waters should have minor-to-negligible public health effects, but may be of more concern for worker safety. Facilities in state waters may have somewhat greater health impacts because they are closer to human population. Greenhouse gas (GHG) emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations. The associated GHG impact relative to benefits of usable energy produced from these operations is not exceptional. GHG emissions linked to well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total emissions.

Water associated with well-stimulation-enabled production in state waters is primarily injected back into producing oil reservoirs and a small fraction into water disposal wells. The volumes requiring disposal are small compared to the volume of water requiring disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, offshore produced-water disposal linked with well-stimulation-enabled production adds little to the hazard of induced seismicity.

Significant data gaps include data concerning the occurrence of well stimulation treatments, information on stimulation-fluid composition, treatment intervals and depths, flowback quantities and compositions, and ultimate disposition of flowback. Data relevant to these issues are insufficient and inadequate for quantitative impact assessments. In some cases, such as flowback quantities and compositions, the information is completely absent. In addition, no studies have been conducted on the toxicity and impacts of well stimulation fluids discharged in federal waters to the marine environment.

In addition to the collection of more data on offshore well stimulation, a recommendation is made to investigate alternatives to ocean disposal of stimulation flowback fluids for facilities in federal waters.

2.2. Introduction

This case study summarizes current practices concerning the use of well stimulation and associated potential environmental impacts for California offshore petroleum-production operations. Operators use hydraulic fracturing (including acid fracturing) and matrix acidizing to improve the flow of oil or gas into a production well, by increasing the effective permeability of the reservoir rock (making flow through the rock easier), removing or bypassing near-wellbore permeability damage from the drilling and well completion process, and reducing the tendency for reservoir rock fines migration that reduces permeability. Hydraulic fracturing can be used to address all three of these problems, whereas matrix acidizing is used primarily to resolve formation damage. Chapter 2 of Volume I provides a more in-depth discussion of well stimulation.

The majority of offshore production takes place without hydraulic fracturing (Volume I, Chapter 3). Ninety percent of the limited hydraulic fracturing activity in California is waters conducted on man-made islands close to the Los Angeles coastline in the Wilmington field; little hydraulic fracturing activity is documented on platforms. Operations on close-to-shore, man-made islands resemble onshore oil production activities. On these islands, operators conduct about 1–2 hydraulic fracturing treatments in the 4–9 wells completed per month. The only available survey of stimulation in federal waters records that 22 fracturing stimulations occurred or were planned from 1992 through 2013. About 10–40% of fracturing operations in wells in California waters and half of operations in U.S. waters were frac-packs (Volume I, Chapter 3). No instances of acid fracturing were recorded for state or federal offshore facilities.

Offshore production extracts petroleum fluids (oil and/or gas) from a petroleum reservoir situated beneath the ocean. While offshore production mainly takes place through wells that are drilled from offshore platforms or artificial islands, in a few cases, onshore wells are directionally drilled to enable petroleum production from offshore reservoirs.

Offshore petroleum production operations in California occur under either state or federal jurisdiction. State authority extends out to three geographic miles from the coastline; operations conducted further than three geographic miles from the coastline fall under federal authority. Currently, state waters host four offshore platforms and five artificial islands used for petroleum production in state waters, along with offshore production from onshore wells. Federal waters off the coast of California host 23 offshore platforms.

The currently operating facilities in state waters are located between 0.2 and 3.2 km (0.1–2 mi) from shore in water depths ranging from 6.7 to 64 m (22 to 211 ft). The platforms in federal waters are located between 6 and 16.9 km (3.7 and 10.5 mi) from shore in water depths ranging from 29 to 365 m (95 to 1,198 ft). Figure 2.2-1 shows the facility locations in and near the Santa Barbara channel and south of Los Angeles in or near San Pedro Bay. Most of the current petroleum production platforms (19 of 23) in federal waters are in or near the Santa Barbara Channel, and most of the petroleum production platforms (3 of 4) and artificial islands (4 of 5) in state waters are south of Los Angeles, in or near San Pedro Bay. Note that some reservoirs in state waters are produced from both onshore and offshore wells.

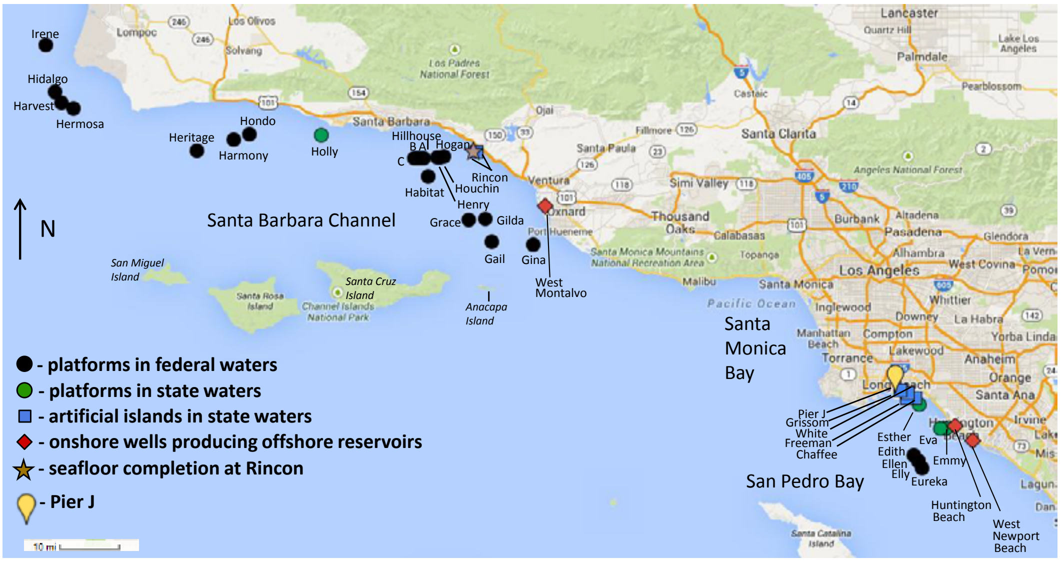


Figure 2.2-1. Map of current California offshore petroleum production facilities. All facility names are shown; onshore wells are labeled using the associated petroleum field.

Figure 2.2-2. Map of abandoned offshore production facilities. All facility names are shown; onshore wells and seafloor completions are labeled using the associated petroleum field.

Eight platforms in state waters in the Santa Barbara Channel and one artificial island in San Pedro Bay have been abandoned and removed (Figure 2.2-2). Four piers used for petroleum production and four seafloor completions[1] in the Santa Barbara Channel have been abandoned. Four onshore sites in the Santa Barbara Channel and two onshore sites in Santa Monica Bay have also been abandoned. The locations of abandoned (and generally older) facilities in Figure 2.2-2 show, by comparison with Figure 2.2-1, the trend in offshore development over time, from locations along the shoreline and near-shore to locations further from the shoreline.

Following this introduction, Section 2.3 discusses the historical development of offshore oil production. Section 2.4 covers offshore reservoir petroleum geology and reservoir characteristics for currently operating offshore reservoirs, along with historical oil and gas production data. Section 2.5 provides a detailed description of the offshore production facilities in terms of location, facility type, water depth, fluids handling, and past use of well stimulation. Section 2.6 presents information on wastewater discharge to the ocean. One important operational difference between the offshore facilities in state and federal waters is that those in state waters are not permitted to discharge wastewater into the ocean, but those in federal waters are allowed to discharge wastewater into the ocean (subject to certain restrictions). The National Pollutant Discharge Elimination System (NPDES) permits for ocean disposal from platforms in federal waters are described. Air emissions from offshore oil and gas operations are also summarized. The impacts of ocean wastewater discharge and air emissions are discussed in Section 2.7. The potential effect of wastewater injection on induced seismicity is also addressed. Section 2.8 presents the findings, conclusions, and recommendations based on this case study.

2.3. Historical Development of Offshore Oil and Gas Production in California

2.3.1. Initial Oil Development

The initial development of oil production offshore followed observations of oil and gas seeps. Active seeps offshore have been observed from Point Conception to Huntington Beach south of Los Angeles. Figure 2.3-1 shows offshore seeps cataloged by Wilkinson (1972). The pattern of these natural oil seeps roughly correlate with the pattern of offshore oil production in Figures 2.2-1 and 2.2-2.

The first offshore development in California occurred at Summerland near Santa Barbara in 1898 (Figure 2.3-2), based on observations of oil and gas seeps in the area (Love et al., 2003). By 1902, oil drilling and production was conducted from as many as 11 wooden piers extending into the ocean up to 375 m (1,250 ft), as well as from the shoreline (Love et al., 2003; Schempf, 2004). Operators drilled more than 400 sea wells between 1898

---

1. A seafloor (or subsea) completion is one in which the producing well does not include a vertical conduit from the wellhead back to a fixed access structure. A subsea well typically has a production tree sitting on the ocean floor to which a flow line is connected allowing production to another structure, a floating production vessel, or occasionally back to a shore-based facility (NPC, 2011).

and 1902 (Grosbard, 2002). A strong storm in 1903 severely damaged this early phase of the Summerland oil field, and high tides and storms finally destroyed the last pier and oil production in 1939 (Grosbard, 2002).

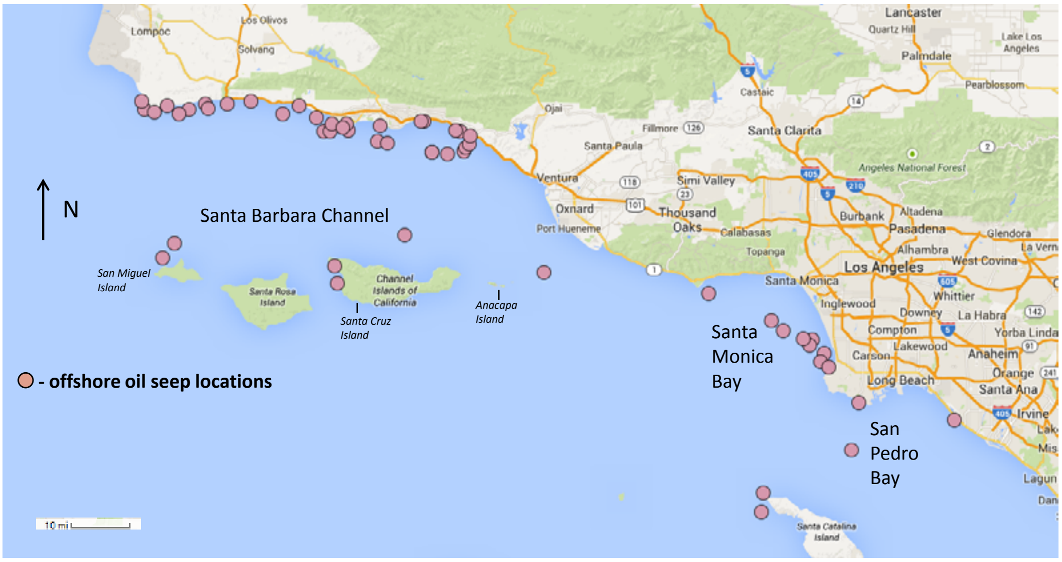


Figure 2.3-1. Offshore oil seep locations (based on data from Wilkinson, 1972).

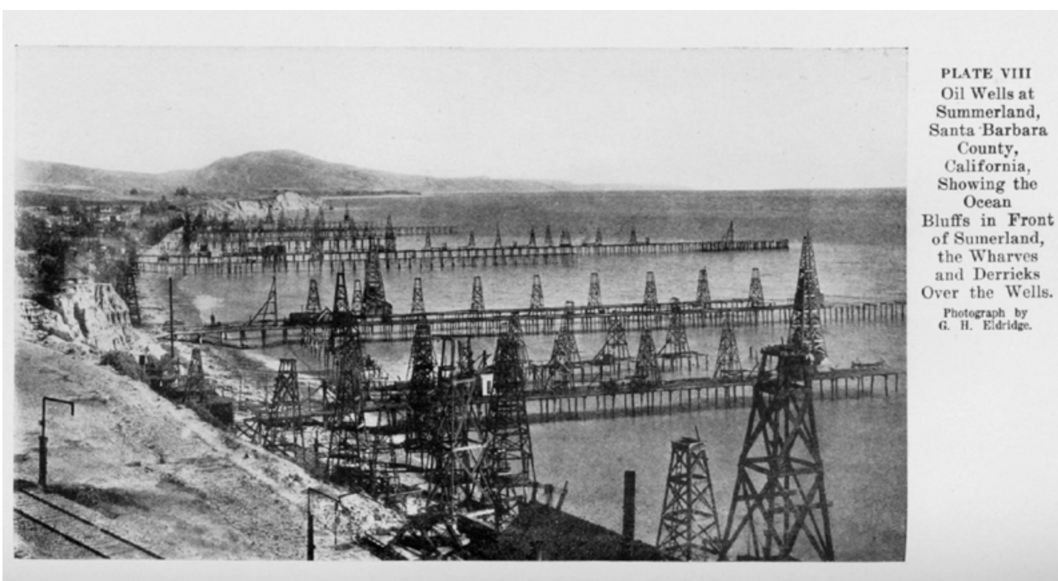


Figure 2.3-2. Summerland offshore oil development circa 1900. (NOAA, 2015).

By 1944, operators constructed several piers as far as 700 m (2,300 ft) offshore into 35 ft of water at Elwood, also near Santa Barbara (Frame, 1960). However, subsequent production from Elwood favored the use of directionally drilled wells from the tidelands. The Rincon field near Ventura also used piers for offshore development (Frame, 1960).

From 1930 to 1960, operators drilled “directional” wells from onshore into near-shore reservoirs at Huntington Beach, Redondo Beach, and West Newport Beach near Los Angeles; and at Gaviota and West Montalvo in the Santa Barbara Channel (Frame, 1960). These reports include one of the earliest successes in directional drilling in 1932 for wells drilled onshore from Huntington Beach to access oil resources under the ocean (Weaver, 1937) (Figure 2.3-3). Also during this period, the first offshore platform was installed offshore California at Rincon in 1932. This platform, called the “Steel Island,” stood in 12 m (38 ft) of water about 0.8 km (0.5 mi) offshore (Figure 2.3-3). Steel Island was destroyed by storms in 1940, and for the first time divers were used to remove well casing and set abandonment plugs (Silcox et al., 1987).

Figure 2.3-3. (a) Huntington Beach (1932) - first directional drilling from onshore under the ocean. (Wentworth, 1998); (b) Steel Island (1932) – first offshore platform. (Love, 2003).

2.3.2 Initial Post World War II Development

The development of modern offshore platforms started in the latter part of the 1950s. The first post-World War II free-standing platform to be used offshore California was Platform Hazel (Figure 2.3-4), installed in 1958 in 30 m (100 ft) of water about 2.4 km (1.5 mi) offshore to produce from the Summerland offshore oil field (Frame, 1960; Santa Barbara, 2015a). Platform Hazel was abandoned and removed in 1996.

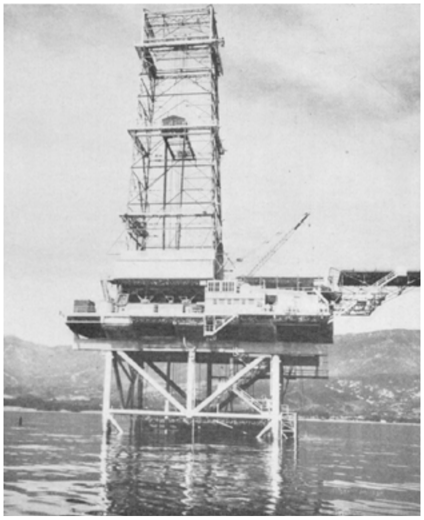
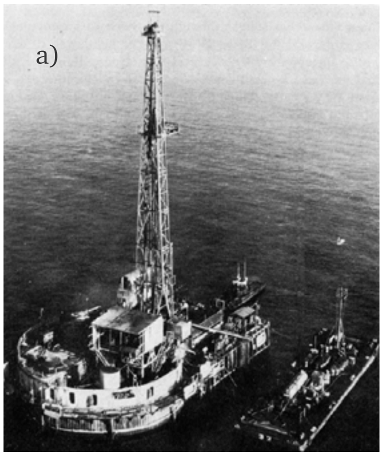


Figure 2.3-4. Platform Hazel (1958). (Carlisle et al., 1964).

In addition to offshore platforms, operators began to build artificial islands for offshore petroleum production. The first artificial island, Belmont Island, constructed near Long Beach Harbor in 1954 to produce the Belmont field (Figure 2.3-5), stood about 2.4 km (1.5 mi) offshore in about 13 m (42 ft) of water (Ahuja et al., 2003) and was decommissioned and removed in 2002. Rincon Island was constructed northwest of Ventura to produce the Rincon field offshore. The island stands about 853 m (2,800 ft) offshore in about 14 m (45 ft) of water and is the only artificial island connected to the mainland by a causeway (Yerkes et al., 1969) (Figure 2.3-5).



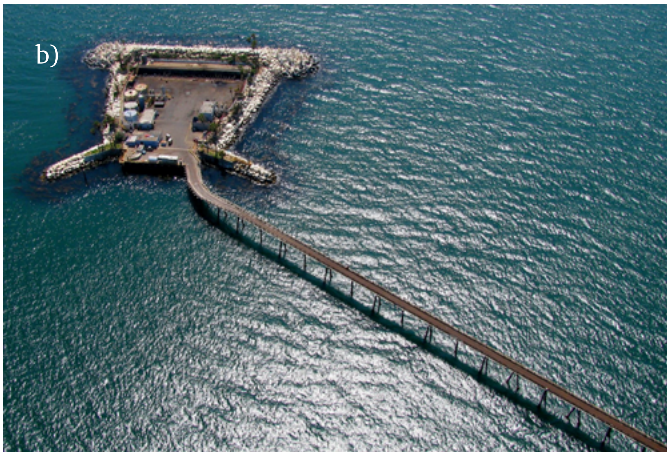


Figure 2.3-5. Offshore Artificial Islands. (a) Belmont Island (1954) - first offshore island. (McGuffee, 2002); (b) Rincon Island and causeway (1958). (Wikimedia Commons, 2015).

Offshore development accelerated in the 1960s, emphasizing the use of offshore platforms but also utilizing artificial islands. In the offshore Los Angeles area, Island Esther was installed near Huntington Beach in 1964. Islands Grissom (Figure 2.3-6), White, Chaffee, and Freeman, known collectively as "THUMS" (for the Texaco, Humble, Union, Mobil, and Shell oil companies that initially developed these islands), were all installed in 1967 offshore of Long Beach.

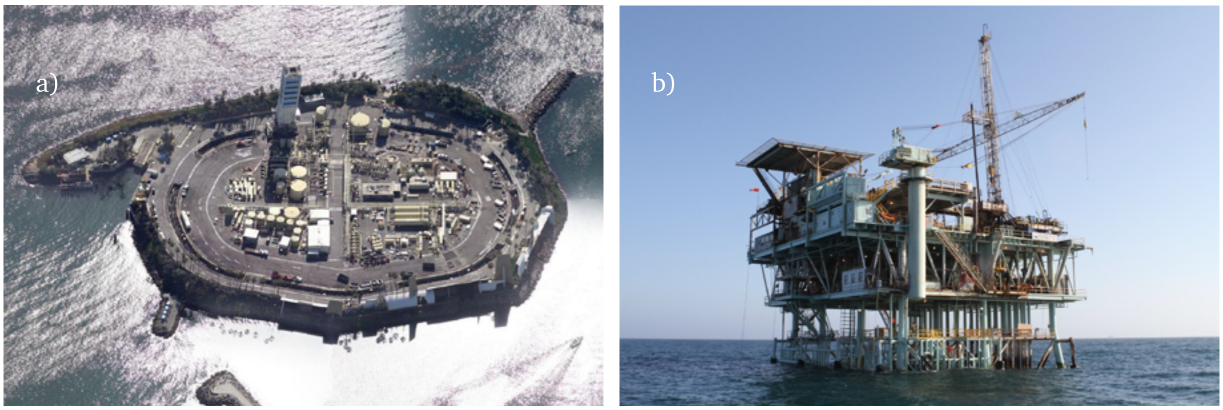


Figure 2.3-6. (a) Grissom Island (1967) – one of the THUMS islands. (The Atlantic Photo, 2014); (b) Platform Hogan (1967) – first platform installed in federal waters. (Carpenter, 2011).

The THUMS islands continue to operate; however, Esther was later converted to a platform after storms damaged the island in the winter of 1982–83. Platforms Emmy (1963) and Eva (1964) installed off of Huntington Beach still operate. In the 1960s, operators constructed platforms in the state waters of the Santa Barbara Channel, including Hilda (1960), Helen (1960), Harry (1961), Herman (1963), Hope (1965), Heidi (1966), and Holly (1966) (see Figures 2.2-1 and 2.2-2); all except Holly have since been abandoned and removed. Platforms Hogan (1967) (Figure 2.3-6), Houchin (1968), A (1968), B (1968), and Hillhouse (1969) in federal waters of the Santa Barbara Channel area continue to operate (California State Lands Commission, 1999). In addition to these facilities, offshore wells were also installed as "seafloor completions" in the Santa Barbara Channel area. In some cases (shown on Figure 2.2-2), these completions were not associated with a platform and connected directly to shore; in other cases, seafloor completions were linked to a platform, e.g., platform Herman (Adams, 1972).

2.3.3. 1969 Santa Barbara Oil Spill

The rapid-pace offshore oil production facility development slowed markedly following the Santa Barbara oil spill in 1969. The blowout and oil spill occurred at platform A, operated by Union Oil, about 11 km (7 mi) southeast of Santa Barbara (Figure 2.2-1). The disaster was a result of operator errors during drilling operations (not well stimulation) that led to a loss of well control and an insufficient casing length in the upper part of the well (see Box 2.3-1). In total, more than 12,700 m^3 (80,000 barrels or 3,360,000 gallons) of oil leaked into the ocean. The spill spread over 2070 km^2 (800 mi^2) of ocean around platform A, and 35 miles of mainland coastline were coated with an oil layer up to 0.15 m (0.5 ft) thick (Engle, 2006). The spill surrounded Anacapa Island, and parts of Santa Cruz and Santa Rosa Islands (Figure 2.3-7). The environmental cost of the spill included killing over 3,600 sea birds and a large number of seals and dolphins.

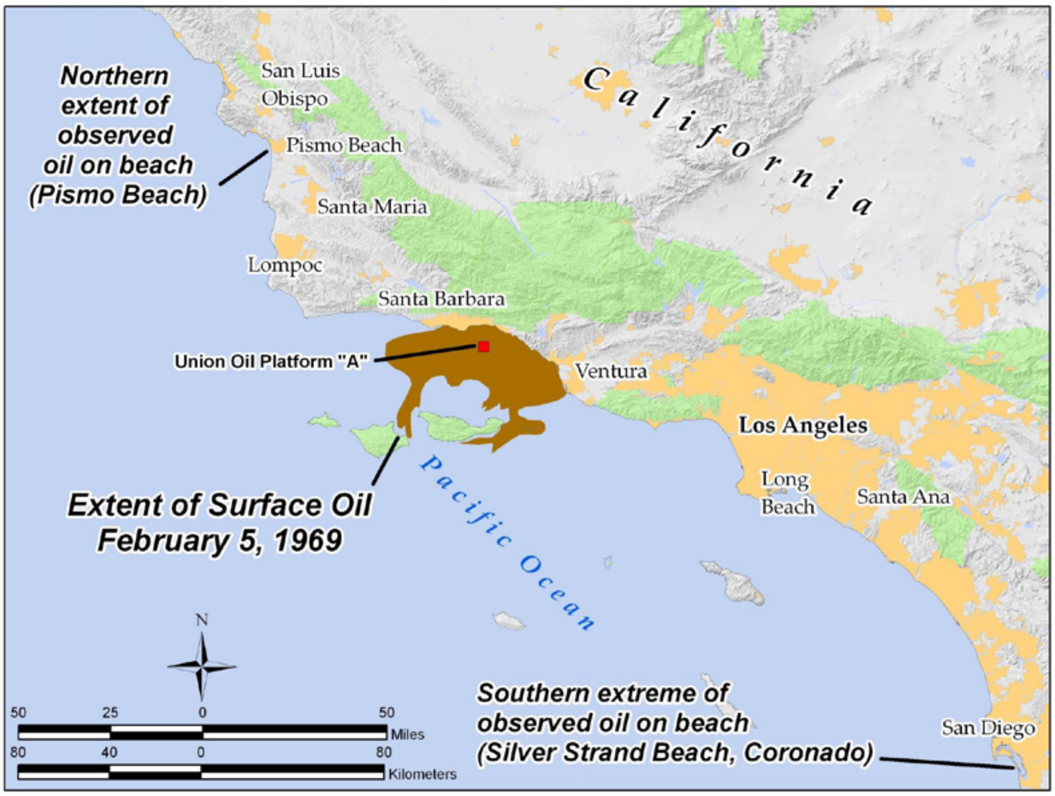


Figure 2.3-7. A view of Santa Barbara Channel with the location of platform "A" during the 1969 well blowout including the extent of the oil spill. (University of California, Santa Barbara, 2011).

Box 2.3-1 – What Caused the Platform A Blowout?

Platform A was installed in September 1968 in federal waters about 8.9 km (5.5 mi) from the coast in 57.3 m (188 ft) of water. The blowout began on January 28, 1969, during drilling of the 5th development well, 402-A-21 (The Resources Agency of California, 1971). The first stage of the blowout started while pulling the drill pipe from the directionally drilled well at a measured depth of 976 m (3,203 ft). The drill pipe was pulled faster than the drilling mud could replace the pipe volume, leading to a pressure drop in the well. The pressure drop resulted in petroleum reservoir fluids rising up the well. The rising pressure caused drilling mud to flow up through the drill pipe onto the platform, followed by an oil condensate mist from the reservoir (McCulloh, 1969). The remaining drill pipe still in the hole was dropped to the bottom of the hole, and the blowout preventer blind rams were closed to halt the gas flow about 15 minutes after the blowout began (Adams, 1969). While this stopped the flow up the well, pressure from the reservoir began to build up inside the well. The well only had 73 m (238 ft) of conductor casing and no surface casing, instead of the usual 91 m (300 ft) of conductor casing and 265 m (870 ft) of surface casing normally required (Santa Barbara, 2015b). The use of a shorter casing had been requested by Union Oil and approved by the U.S. Geological Survey. The pressure released from the reservoir blew out around the shoe of the conductor casing and fractured the surrounding seafloor as far away as 244 m (800 ft) from the platform, creating an underground blowout (Hauser and Guerard, 1993; The Resources Agency of California, 1971). Gas and oil leaked into the ocean from five locations on the seafloor around the well. The blowout continued for eleven days until the well was killed by pumping mud down the well. While this stopped most of the leakage, lower-rate leakage continued for months (NOAA, 1992).

2.3.4. Development in the 1970s and 1980s

During the 1970s, development of offshore California slowed. Only platforms Hondo (1976), C (1977), Henry (1979), and Grace (1979) were installed during this decade, all in federal waters. The development pace accelerated again during the 1980s with the installation of platforms Gina (1980), Elly (1980), Ellen (1980), Gilda (1981), Habitat (1981), Edith (1983), Eureka (1984), Hermosa (1985), Harvest (1985), Irene (1985), Hidalgo (1986), Gail (1987), Harmony (1989), and Heritage (1989) (Figure 2.3-8), all in federal waters (CSLC, 1999). In 1990, island Esther in San Pedro Bay (state waters) was converted to platform Esther.

Figure 2.3-8. Platform Heritage (1989) – the most recent platform installed in federal waters. (MMS, 2007).

The development of additional offshore production facilities stopped after 1990. This drop-off in activity was directly related to the moratoriums on offshore oil and gas leasing for both federal waters since 1982 and state waters since 1969 (Sutherland Asbill & Brennan LLP, 2008; Chiang, 2009). The moratorium for state waters became part of California law in 1994 (California Coastal Sanctuary Act, 1994). Although the moratorium in federal waters was lifted in 2008, no new offshore leases were sold (Sutherland Asbill and Brennan LLP, 2008; BOEM, 2015a). In November 2011, the Obama Administration imposed a five-year moratorium starting in 2012 that closed all offshore California to new oil and gas drilling (U.S. House of Representatives, 2011).

2.4. Petroleum Geology and Characteristics of California Offshore Oil and Gas Reservoirs

This section draws upon the petroleum geology of offshore California presented in Chapter 4 of Volume I and provides additional information about reservoir rock characteristics and petroleum production.

Petroleum source rocks and reservoir rocks all occur in sedimentary basins. Sedimentary basins are created where tectonic and other geologic processes (such as geothermal contraction and erosion) create depressions at the surface. Sediments created by erosion of rock, such as through fluvial (water driven) and aeolian (wind driven) processes, lead to the movement of sediments driven by gravitational forces into these depressions. Over millions of years, these depressions fill up with sediments to become sedimentary basins. Figure 2.4-1 shows the offshore sedimentary basins for California, Oregon, and Washington states.

Most of the oil and gas fields in California are located in structural basins (DOGGR, 1982; 1992; 1998) formed over the past 23 million years. These basins are filled with mainly marine sedimentary rocks, originally including both biogenic (produced by marine organisms) and clastic (derived by erosion of existing rocks) sediments. In each basin, geologists have identified distinct packages of sedimentary rocks as formations, which share similar time-depositional sequences and have distinctive characteristics that can be mapped.

Oil and gas accumulations (also known as reservoirs or pools) are found within oil and gas fields. The reservoirs are organized into groups called plays that have common factors associated with hydrocarbon generation, accumulation, and entrapment (BOEM, 2014a). In the BOEM (2014a) assessment of offshore oil and gas resources for the Pacific Outer Continental Shelf Region, plays were organized according to source rock, reservoir rock, and trap characteristics of stratigraphic units.

Current offshore oil production comes from the Santa Barbara, Santa Maria, and offshore Los Angeles Basins. Geologic and petrophysical characterization of these basins will be presented first, including both currently operating petroleum reservoirs and other reservoirs within these basins. This will be followed by a discussion of potential future petroleum resources from undeveloped offshore basins.

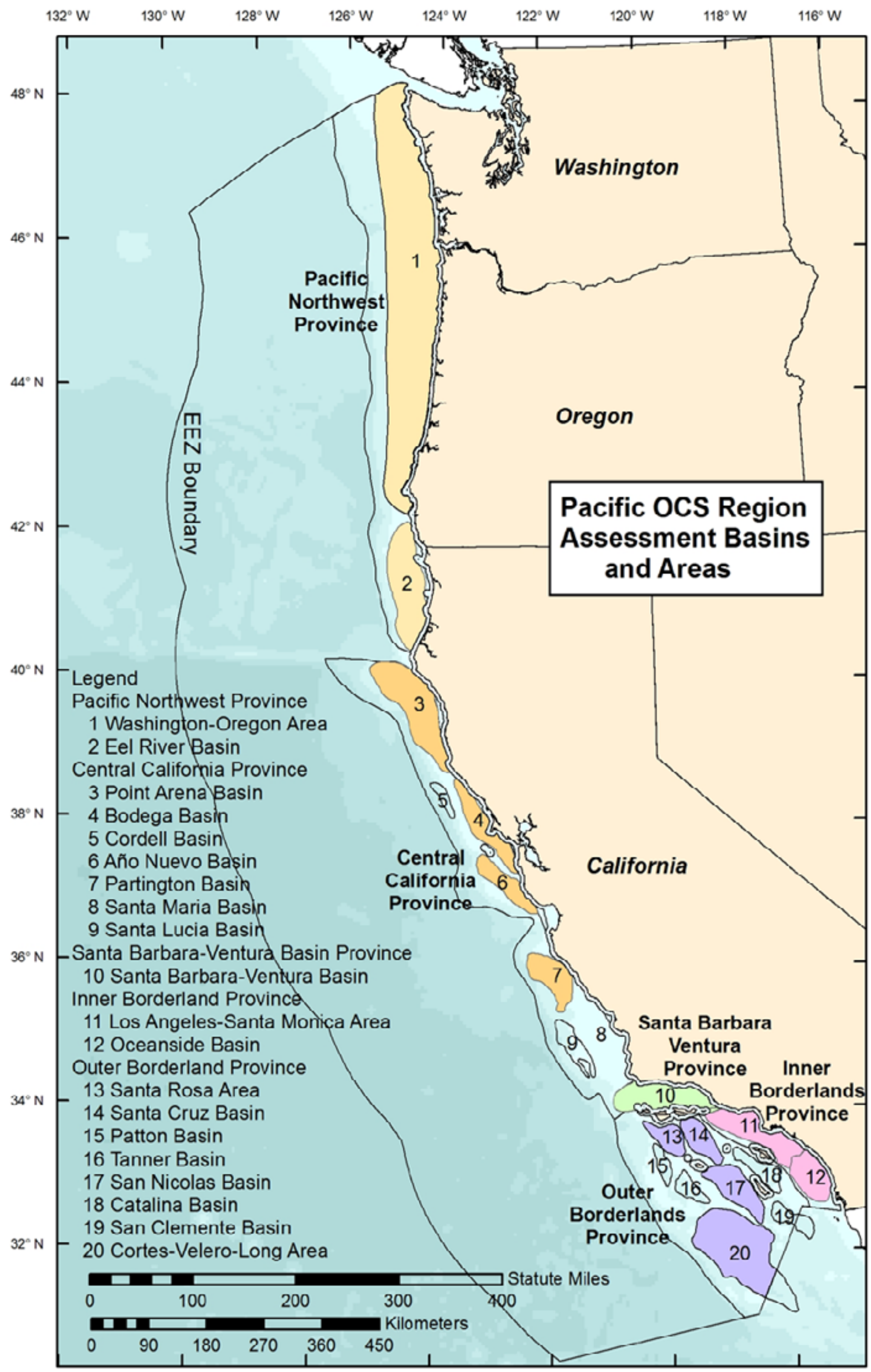


Figure 2.4-1. Provinces and sedimentary basins in and along the Pacific Coast (BOEM, 2014a).

Well stimulation is conducted offshore for the same reasons as onshore – to facilitate production from low permeability reservoirs and to counter the effects of formation damage near the well. The production of oil and gas from a reservoir depends on reservoir permeability, but it is also a function of reservoir thickness, the viscosity of the produced fluids, and other factors (Volume I, Chapter 2). Because of the complexity of the problem, an exact permeability threshold for the use of well stimulation technologies does not exist (Holditch, 2006). However, the likelihood that well stimulation is needed to economically produce oil and gas increases as the reservoir permeability falls below about 10^{-15} square meters (m^2; about 1 millidarcy, md) (e.g., King, 2012). Hydraulic fracturing for low permeability conditions is intended to open permeable fracture pathways to enable oil or gas production. However, hydraulic fracturing technology has been expanded to deal with other oil production issues that occur in moderate-to higher-permeability conventional reservoirs. These other issues are formation damage around the well and sand production into the well. The hydraulic fracturing technology used for these purposes is called "frac and pack" or just "frac-pack" (Sanchez and Tibbles, 2007) and may also be referred to as a "high-rate gravel pack" (Cardno ENTRIX, 2012). The American Petroleum Institute (API) notes that frac-packs are a common well stimulation method used for offshore oil and gas production sites that often have moderate to high permeability and sand control problems (API, 2013). Therefore, hydraulic fracturing may be used under any condition of reservoir permeability, but is not essential (i.e., not used in all cases) when permeabilities exceed about 10 md (about 10^{-14} m^2). California oil and gas reservoirs are predominantly rich in silicate rocks, which means that the form of matrix acidizing used is called "sandstone acidizing" (Volume I, Chapter 2). This type of acidizing is normally used only when formation damage near the well is impeding flow into the well. This is because penetration of a sandstone acidizing treatment into the formation is generally only about 0.3 m (1 ft). However, there is much less known about sandstone acidizing in siliceous reservoirs with permeable natural fractures, such as in some parts of the Monterey Formation (Kalfayan, 2008). In these circumstances, sandstone acidizing may be able to penetrate and remove natural or drilling-induced blockage in fractures deeper into the formation (Rowe et al., 2004; Patton et al., 2003; Kalfayan, 2008).

2.4.1. Santa Barbara Basin

The Santa Barbara/Ventura Basin is a structurally complex east-west trending synclinal trough, bounded on the north and northeast by the Santa Ynez and San Gabriel faults, and on the south by the Santa Monica Mountains and Channel Islands. The onshore and offshore parts are a single continuous structure. The onshore part is referred to as the Ventura Basin, while the offshore part is known as the Santa Barbara Basin. The basin has been structurally deformed by the active tectonic processes associated with the Pacific/North American plate margin. The stratigraphic column in Figure 2.4-2 shows that the sequence of formations has resulted in oil reservoirs that consist mainly of sandstones and the Monterey, which is a fractured siliceous shale.

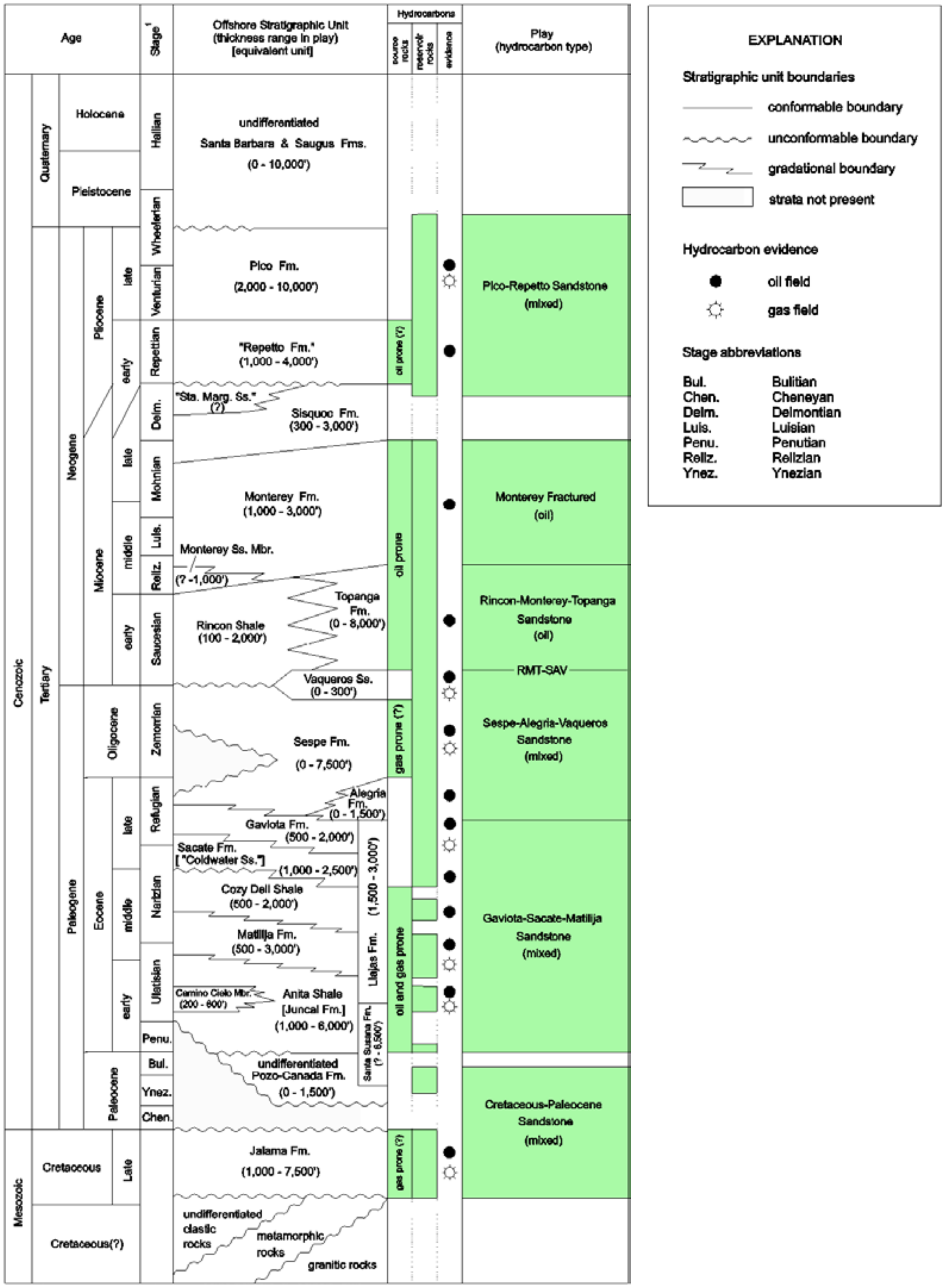
The Santa Barbara/Ventura Basin exhibits as much as 7,000 m (23,000 ft) of structural relief on the base of the Miocene section (Tennyson and Isaacs, 2001) and a succession of Upper Cretaceous to Quaternary sedimentary rocks as much as 11,000 m (36,000 ft) thick. In the primary depocenter, the Plio-Pleistocene strata are more than 6,100 m (20,000 ft) thick (Dibblee, 1988; Nagle and Parker, 1971).

There are twelve petroleum fields under production in the Santa Barbara Basin shown in Figure 2.4-3, which also shows the three currently producing oil fields in the Santa Maria Basin. There are four plays identified in this basin in federal waters (BOEM, 2014a). The Pico-Repetto (PR) play consists of Pliocene and early Pleistocene turbidite sandstones. The Fractured Monterey (FM) play consists of middle to late Miocene siliceous fractured shale reservoirs of the Monterey Formation. The Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros (RMT-SAV) sandstone play consists of late Eocene to middle Miocene reservoirs. The Gaviota-Sacate-Matilija (GSM) play consists of Eocene to early Oligocene sandstones of various origins deposited as turbidites, fans, channels, and near-shore bars. The plays in state waters that are currently producing are the Neogene and Paleogene plays (Keller, 1995).

Production statistics for the Santa Barbara Basin are given in Table 2.4-1. Annual production in 2013 for all of offshore California shows about 64% of the oil and 75% of the gas is produced in the Santa Barbara Basin. About 90% of oil and gas production from the Santa Barbara Basin comes from six fields—Hondo, Pescado, Sacate, South Elwood, Carpinteria, and Dos Cuadras—that lie along the Rincon trend and its continuation along the five-mile trend and splay (Figure 2.4-3). The Hondo, Pescado, Sacate, and South Elwood fields produce mainly from fractured, siliceous, Miocene reservoir rock in the Fractured Monterey play. The Carpinteria and Dos Cuadras fields produce mainly from Pliocene turbidite sandstones in the Pico and "Repetto" (lower Pico) play. The Rincon field itself also lies along this trend but has only minor amounts of oil and gas production. The production levels for the Santa Barbara Basin in 2013 are about 8.6% of the state onshore oil production and about 15% of the gas production.

Other undeveloped reservoirs are shown in Figure 2.4-3. These are expected to be similar to the existing reservoirs, in that most of the remaining oil is likely to be in the identified plays, with current oil production in the Santa Barbara Basin today.

The source rocks for reservoirs in the Pico, "Repetto," and Monterey Formations are likely to be in the Miocene Monterey Formation (Monterey Formation reservoir rocks lie in the same formation as the source rock). Other older source rocks include Cretaceous to Eocene organic shales. Sources for high gravity oil include Cretaceous, Eocene, and Miocene shales. Sources for low gravity, high sulfur oil are most likely Miocene formations.



V

Figure 2.4-2. Stratigraphic column of the Santa Barbara-Ventura Basin showing formation thickness ranges (ft) and source rock and reservoir rock hydrocarbon classifications (BOEM, 2014a).

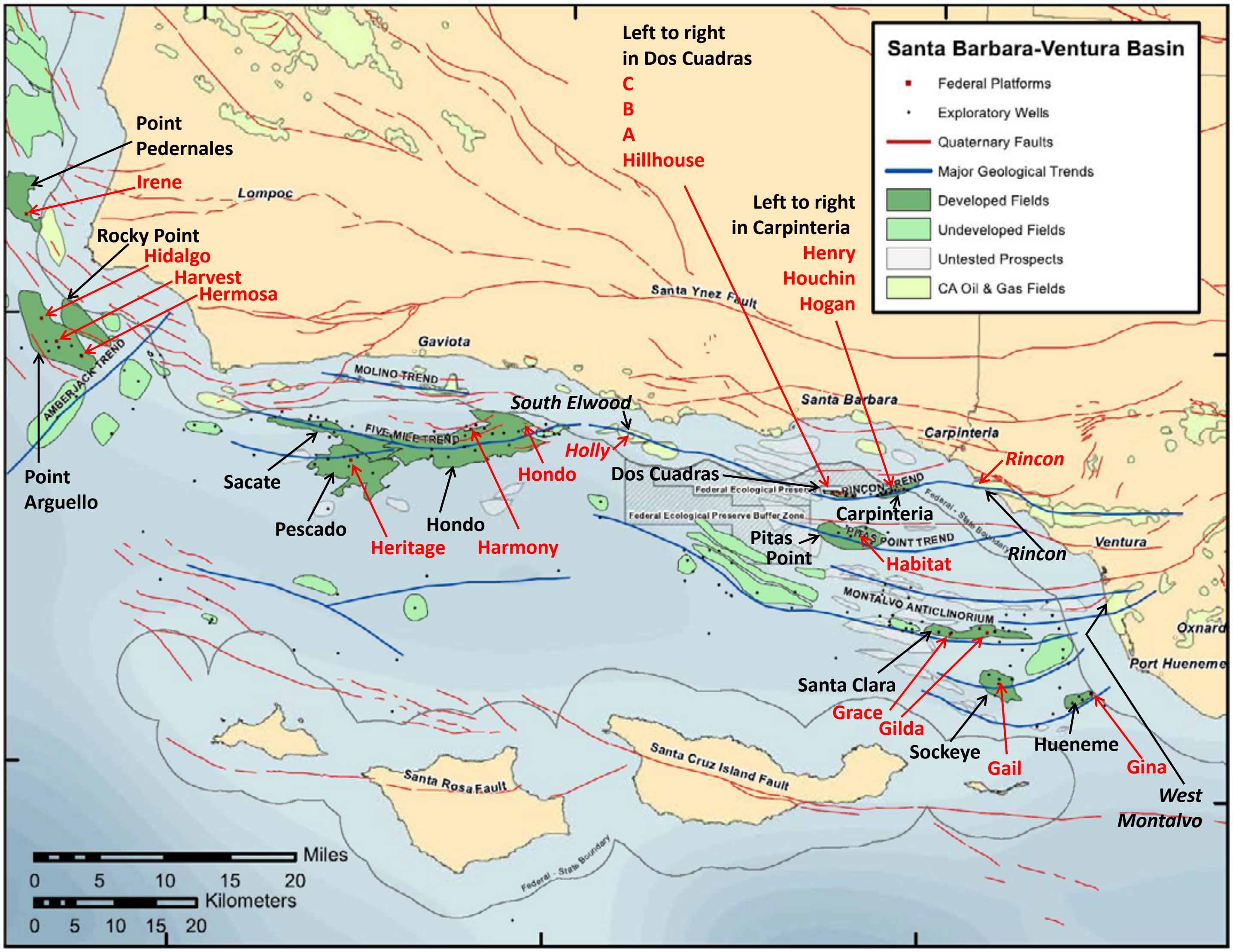


Figure 2.4-3. Operating oil fields and production facilities in the Santa Barbara and Santa Maria Basins showing faults and geologic trends. Modified from BOEM (2014a). Fields Point Pedernales, Point Arguello, and Rocky Point are in the Santa Maria Basin. All other fields are in the Santa Barbara Basin. Black font labels with black arrows denote oil fields. Red font labels with red arrows denote offshore production facilities. Note that offshore production from the West Montalvo field is performed using wells spud onshore. Facilities and field names in state waters are italicized.

Properties of the main reservoirs currently under production are given in Table 2.4-2. Notably, reservoir depths are mainly in excess of 1000 m below the ocean floor, and reservoir permeabilities are in the millidarcy to darcy range (where 1 millidarcy approximately equals 10^{15} m^2 and 1 darcy approximately equals 10^{-12} m^2).

The API gravities show that the crude oils produced are mostly heavy to medium, with a few that are at the low end of the light crude category.[2] Only the lower end of the permeability ranges are below 10 md (about 10^{-14} m^2); therefore, hydraulic fracturing is not likely to be essential for petroleum production.

Table 2.4-1. Production and resource estimates for currently producing fields in the Santa Barbara Basin in 2013 (BOEM, 2013; DOGGR, 2010, 2011, 2012, 2013, 2014a).

Field**	**Original Recoverable Reserves**		**Cumulative Production**		**Annual Production**		**Remaining Reserves**	
	Oil, (m^3) x10^6 (bbl#) x10^6	Gas, (m^3) x10^6 (Mcf##) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Carpinteria	11.8 (74.1)	1770 (62.5)	11.4 (71.5)	1,690 (59.8)	0.0592 (0.373)	11.4 (0.402)	0.414 (2.61)	77.5 (2.74)
Dos Cuadras	44.5 (280)	4,980 (176)	42.5 (267)	4,470 (158)	0.157 (0.988)	46.6 (1.65)	2.04 (12.8)	508 (17.9)
Hondo	62.4 (393)	22,400 (793)	48.7 (306)	19,000 (670)	0.814 (5.12)	319 (11.3)	13.8 (86.8)	8,970 (317)
Hueneme	1.92 (12.1)	347 (12.3)	1.87 (11.8)	290 (10.3)	0.0171 (0.108)	14.1 (0.499)	0.0513 (0.323)	56.4 (1.99)
Pescado	29.0 (182)	4,750 (168)	22.7 (143)	6,220 (220)	0.369 (2.32)	97.8 (3.45)	6.29 (39.6)	2,350 (82.9)
Pitas Point	0.0334 (0.211)	6,770 (239)	0.0333 (0.209)	6,590 (233)	2.19×10^{-5} (1.38×10^{-4})	4.70 (0.166)	1.60×10^{-4} (1.01×10^{-3})	186 (6.56)
Sacate	19.5 (123)	3,120 (110)	7.00 (44.0)	1,210 (42.7)	0.566 (3.56)	131 (4.64)	12.5 (78.6)	1,910 (67.6)
Santa Clara	7.67 (48.3)	2,040 (71.9)	7.28 (45.8)	1,970 (69.6)	0.0604 (0.380)	9.78 (0.345)	0.390 (2.45)	65.9 (2.33)
Sockeye	8.38 (52.7)	3,050 (108)	7.24 (45.5)	2,760 (97.5)	0.156 (0.984)	32.8(1.16)	1.14 (7.20)	291 (10.3)
South Elwood	NA	NA	12.1 (75.9)	1,780 (62.7)	0.276 (1.73)	27.0 (0.954)	NA	NA
Rincon	NA	NA	0.0101 (0.0636)	1.47 (0.0518)	0.00108 (0.00680)	0.0489 (0.00172)	NA	NA
West Montalvo	1.66 (10.4)	194 (6.84)	1.53 (9.65)	167 (5.91)	0.0574 (0.361)	1.87 (0.0660)	0.128 (0.803)	26.2 (0.927)

Volumes of gas that have been injected into the reservoir are added to remaining reserves (Hondo and Pescado) NA – not available; # bbl = oil barrel (one bbl = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7481 gallons) The South Elwood, Rincon, and West Montalvo fields are in state waters. All other fields are in federal waters.*

2. The API gravity is a measure of the oil density at a standard temperature of 60° F (American Society for Testing and Materials (ASTM) D287-12b, 2012). A crude oil with API gravity greater than 10° will float on pure water. Crude oil density correlates with viscosity, and both density and viscosity increase with decreasing API gravity (Saniere, 2011; Sattarin et al., 2007). Crude oil is classified as light if the API gravity is greater than 31.1° and as heavy if it is less than 22.3° but greater than 10°. Crude oils with API gravity between 22.3° and 31.1° are classified as medium. Crude oils with API gravity less than 10° are called extra-heavy or bitumen (Saniere, 2011).

Table 2.4-2. Santa Barbara Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993; 1994; DOGGR, 1992; Keller, 1995).

Field	Formation	Epoch	Play	Average Depth (m) (ft)	Net Thickness (m) (ft)	Permeability (m^2) x 10^{15}	Porosity	API Gravity (o)
Carpinteria	P	P	PR	1,010 (3,300)	305 – 351 (1,000-1,150)	1 - 2171	15 - 39	25.5
Dos Cuadras	P(R)	P	PR	488 (1,600)	305 – 319 (1,000-1,050)	49 - 987	15 - 40	25
Hondo	M	M	FM	2,590 (8,500)	10 – 223 (32.8-732)	0.1 - 1678	9 - 23	17
Hondo	V/S	M/O	RMT-SAV	3,050 (10,000)	137 – 223 (449-732)	10 - 1480	10 - 35	35.1
Hueneme	H/S	M/O	RMT-SAV	1,560 (5,100)	46 – 76 (151-249)	1 - 1480	12 - 40	14.5
Pescado	M	M	FM	2,050 (6,710)	366 (1,200)	0.1 - 1678	2 - 30	17
Pitas Point	P(R)	P	PR	3,380 (11,100)	91 (299)	1 - 20	15 - 18	Gas
Santa Clara	P	P	PR	2,150 (7,050)	53 (174)	1 - 197	12 - 40	23
Santa Clara	M	M	FM	2,290 (7,500)	366 (1200)	1 - 1283	3 - 30	28
Sockeye	M	M	FM	1,370 (4,500)	61 – 76 (200-249)	0.1- 987	2 - 30	16.5
Sockeye	US	M/O	RMT-SAV	1,740 (5,700)	259 (850)	1 - 7106	20 - 30	29.5
South Elwood	M	M	N	1,020 (3,350)	152 (499)	NA	NA	25-34
Rincon	P	P	N	1,080 (3,560)	116 (381)	39	22	32
West Montalvo	S	O	P	3,510 (11,500)	762 (2,500)	NA	NA	13-32

Formation: M – Monterey; P – Pico; P(R) – Pico (Repetto); V – Vaqueros; S – Sespe; US – Upper Sespe; H – Hueneme

Epoch: P – Pliocene; M – Miocene; O – Oligocene

Play: PR – Pico-Repetto; FM – Fractured Monterey; RMT-SAV – Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros; N – Neogene; P – Paleogene; NA – not available

2.4.2. Santa Maria Basin

The Santa Maria Offshore Basin is a complexly faulted extensional structure, separated from the Santa Maria Onshore Basin by the Hosgri Fault Zone. Sub-basins bounded by normally faulted basement blocks were rapidly filled by volcanic, biogenic, and siliciclastic rocks of the Lospe, Point Sal, Monterey, Sisquoc, Foxen, and Careaga Formations (Figure 2.4-4). These formations, which directly overlie basement rocks, are more than 3,050 m (10,000 ft) thick. In most areas, Paleogene strata are entirely absent. Near Point Piedras Blancas (Figure 2.4-5), the Neogene stratigraphic section thins to less than 305 m (1,000 ft). In many areas, the Neogene section consists of only the Sisquoc Formation (BOEM, 2014a).

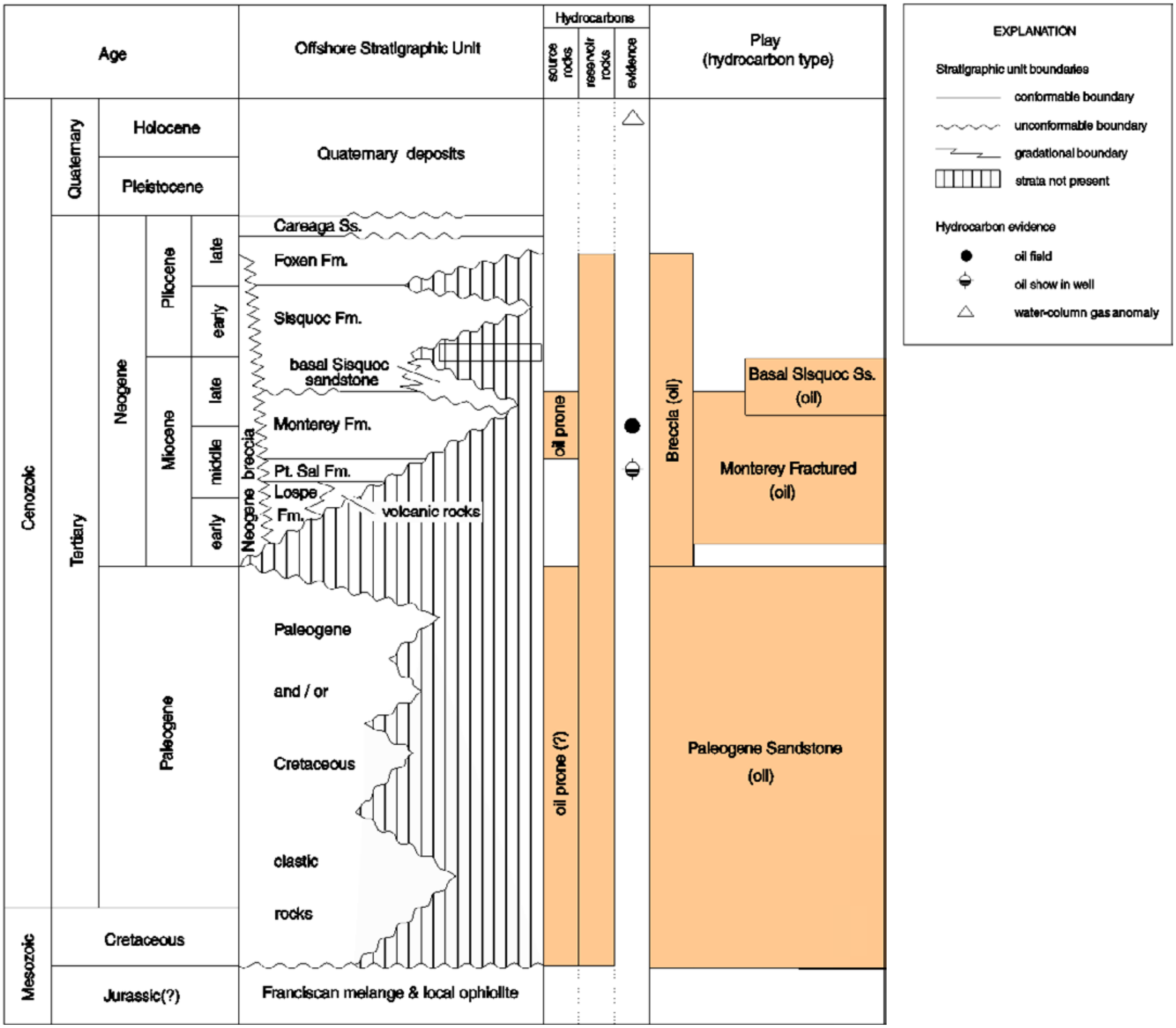


Figure 2.4-4. Stratigraphic column of the Santa Maria Basin showing source rock and reservoir rock hydrocarbon classifications (BOEM, 2014a).

The stratigraphic column in Figure 2.4-4 shows that the sequence of formations contains reservoirs in sandstones and the Monterey, which is a fractured siliceous shale. However, current offshore oil production in the Santa Maria Basin is limited to the fractured Monterey reservoir rock. Three petroleum fields are under production in the Santa Maria Basin, as shown in Figure 2.4-3.

Four petroleum geologic plays have been identified for the Santa Maria—Partington Basin. The Fractured Monterey Play in the Monterey Formation is the only one that has been established offshore. In this play, petroleum reservoirs have been found in fractured Miocene siliceous and dolomitic rocks. The Basal Sisquoc Sandstone play has only been established for the Santa Maria basin onshore. The other two plays, the Breccia play and the Paleogene Sandstone play, remain conceptual. The Monterey Formation is the likely host of source rocks for all of these plays except for some zones in the Paleogene Sandstone play, which may require a source rock in older (Paleogene) strata.

Production statistics for the Santa Barbara Basin are given in Table 2.4-3. Annual production in 2013 for all of offshore California shows about 13% of the oil and 11% of the gas is produced in the Santa Maria Basin. Production from Point Pedernales and Point Arguello were similar in 2013, with production from Rocky Point a distant third place. The production levels for the Santa Maria Basin in 2013 are about 1.7% of the state onshore oil production and about 2.2% of the gas production.

Table 2.4-3. Production and resource estimates for currently producing fields in the Santa Maria Basin in 2013 (BOEM, 2013).

Field**	**Original Recoverable Reserves**		**Cumulative Production**		**Annual Production**		**Remaining Reserves**	
	Oil, (m^3) x10^6 (bbl$^{\#}$) x10^6	Gas, (m^3) x10^6 (Mcf$^{\#\#}$) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Point Arguello	31.8 (200)	3,940 (139)	29.6 (186)	4,870 (172)	0.234 (1.47)	77.3 (2.73)	2.21 (13.9)	1,260 (44.5)
Point Pedernales	16.9 (106)	1,140 (40.3)	14.8 (93.2)	946 (33.4)	0.263 (1.65)	19.1 (0.675)	2.03 (12.8)	195 (6.87)
Rocky Point	3.34 (21.0)	425 (15.0)	0.435 (2.74)	61.5 (2.17)	0.0140 (0.0881)	2.46 (0.0868)	2.90 (18.3)	363 (12.8)

**Volumes of gas that have been injected into the reservoir are added to remaining reserves (Point Arguello)*

***All fields are in federal waters. # bbl = oil barrel (one bbl = 42 gallons);*

Mcf = one thousand cubic feet (one Mcf = 7481 gallons)

Other undeveloped reservoirs are shown in Figure 2.4-5. These are expected to be similar to the existing reservoirs, in that most of the remaining oil is likely to be in the identified plays, with current oil production in the Santa Maria Basin today.

Properties of the main producing reservoirs currently under production are given in Table 2.4-4. Reservoir depths are in excess of 1,000 m below the ocean floor, and reservoir permeabilities are in the millidarcy to darcy range, similar to ranges found for the Santa Barbara Basin. Only the lower end of the permeability ranges are below 10 md (about 10^{-14} m^2); therefore, hydraulic fracturing is not likely to be essential for petroleum production. The API gravities show that the crude oils produced fall into the heavy oil category.

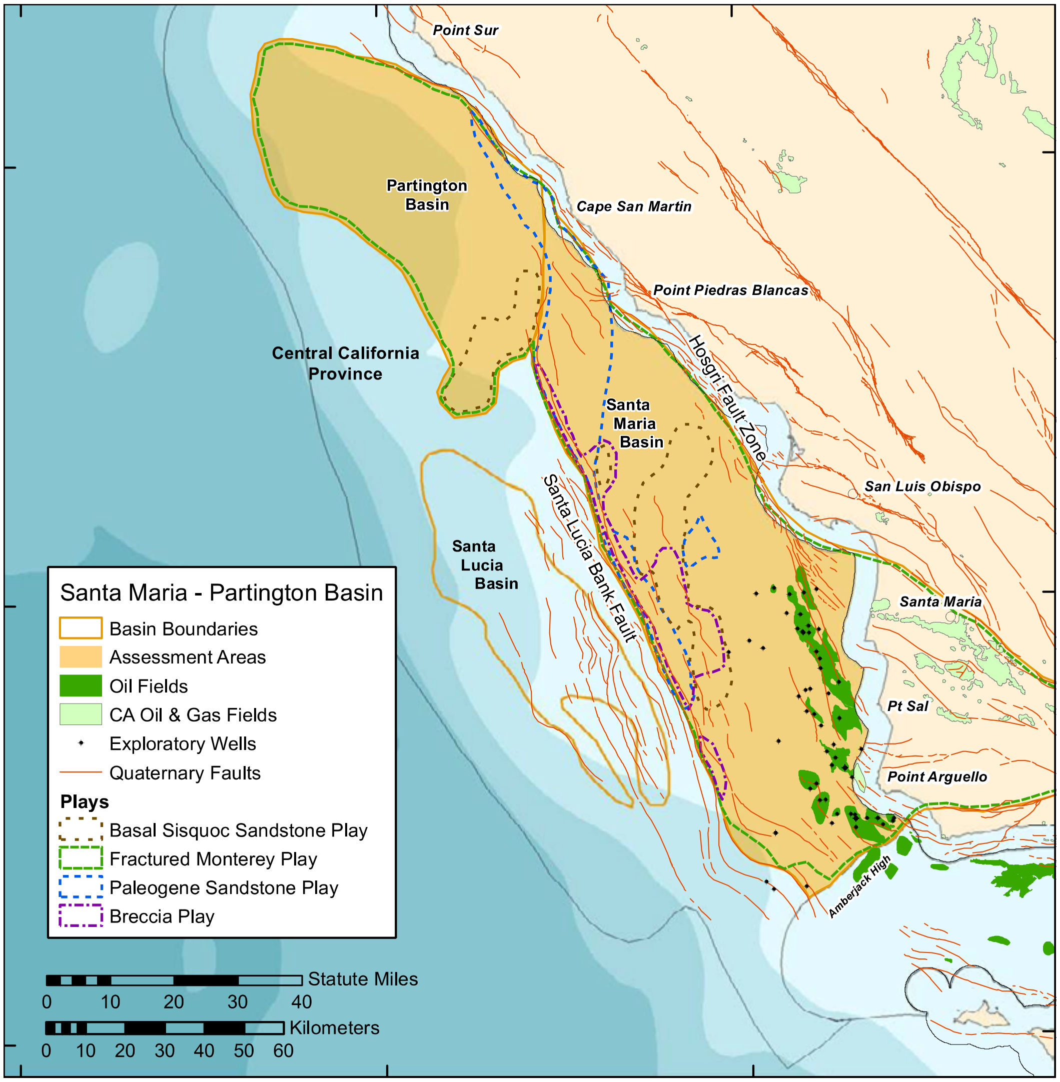


Figure 2.4-5. Partington and Santa Maria Basins (BOEM, 2014a).

Table 2.4-4. Santa Maria Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993).

Field	Formation	Epoch	Play	Average Depths (m)	Net Thickness (m)	Permeability (m^2) x 10^{15}	Porosity	API Gravity (o)
Point Arguello	M	M	FM	2377 (7800)	305 (1000)	1- 2961	10 - 11	18
Point Pedernales	M	M	FM	1524 (5000)	130-145 (427-476)	0.1- 4737	2 - 39	16.3

Formation: M – Monterey, Epoch: M – Miocene , Play: FM – Fractured Monterey

2.4.3. Offshore Los Angeles Basin

The dominant feature of the Los Angeles Basin is the Central Syncline, a poorly understood north-northwest trending 72 km (45 mi) long trough within which organic-rich Miocene sediments have been buried to the oil window and beyond, beneath thick submarine fan deposits (Wright, 1991). The Central Syncline is bordered on the north by east-west trending faults and the southern edge of the Santa Monica Mountains, on the east and northeast by en echelon folds and the Whittier Fault Zone, and on the southwest by the Newport-Inglewood Fault Zone and adjacent southwest structural shelf. The offshore area probably partly shares the thick, porous, and permeable reservoir submarine fan sandstones of latest Miocene Puente Formation and the early Pliocene Repetto Formation, which contain most of the known oil onshore.

Six plays were identified by BOEM (2014a) for the federal waters area. However, only one of these plays, the Puente Fan Sandstone play, is currently being produced. The petroleum reservoirs for this play are found in the Puente and Repetto Formations, in Miocene and Pliocene fan sandstones (Figure 2.4-6).

Source rocks are found at the base of the Miocene Monterey Formation in the “nodular shale” and in Puente Formation Miocene mudstones and shales (BOEM, 2014a).

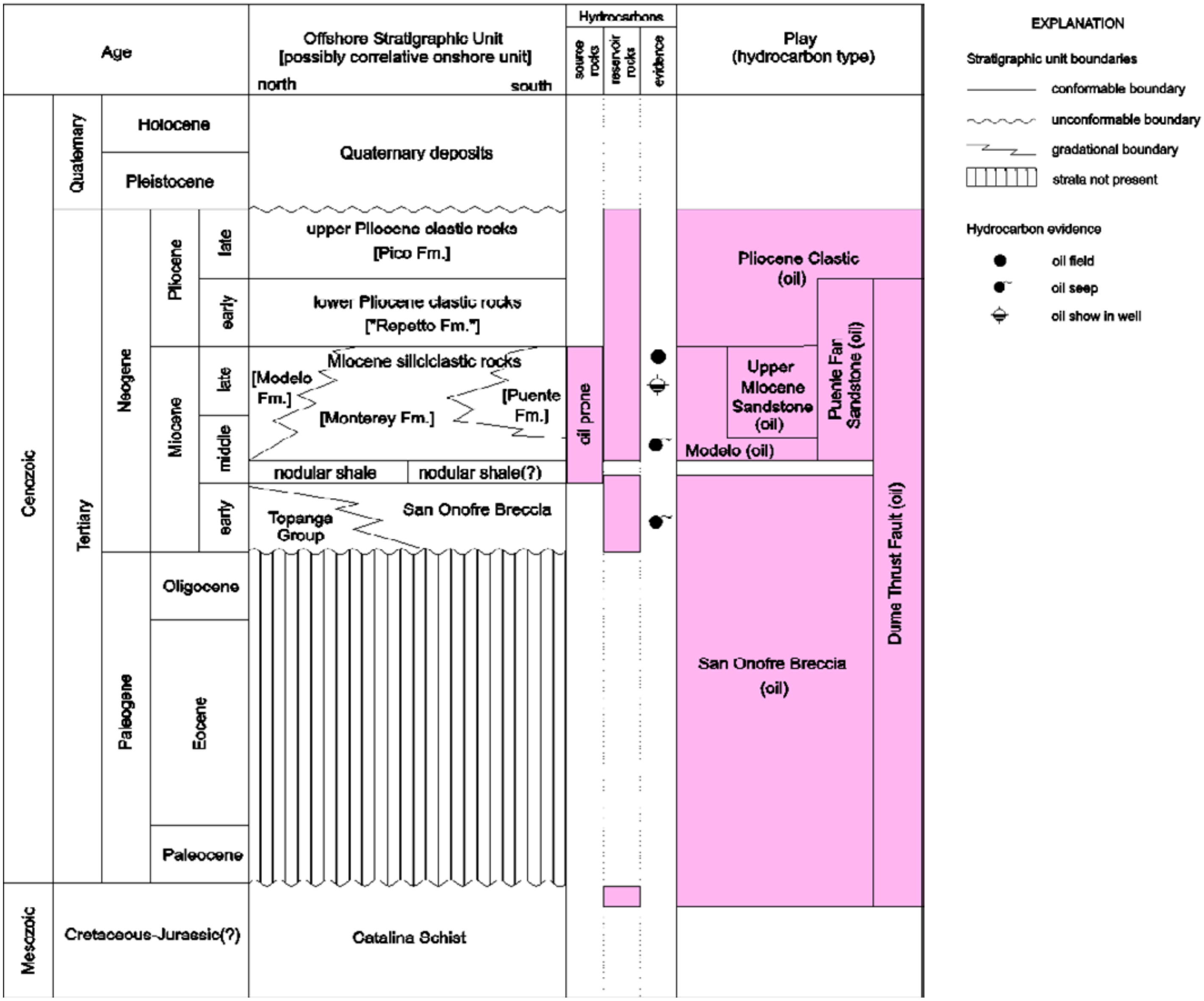


Figure 2.4-6. Offshore Los Angeles – Santa Monica – San Pedro Basins stratigraphy (BOEM, 2014a).

Unlike the Santa Barbara and Santa Maria Basins, most of the oil production activity for this basin is in state waters. There are four oil fields within state waters, three of which contain multiple reservoirs. These reservoirs all lie within the same play identified by Beyer (1995) as the Southwestern Shelf and Adjacent Offshore State Lands play. This play consists mainly of reservoirs in marine turbidite sandstones of Miocene and Pliocene epochs.

Undiscovered petroleum resources are also expected to consist primarily of marine Miocene and Pliocene turbidite sandstones, and possibly, but to a lesser degree, Miocene fractured shale and Cretaceous-Jurrasic conglomerates and breccias from the Catalina Schist.

The source rock for the relatively higher-sulfur oils in producing reservoirs is believed to be the Miocene organic-rich basal unit ("nodular shale") of the Monterey Formation.

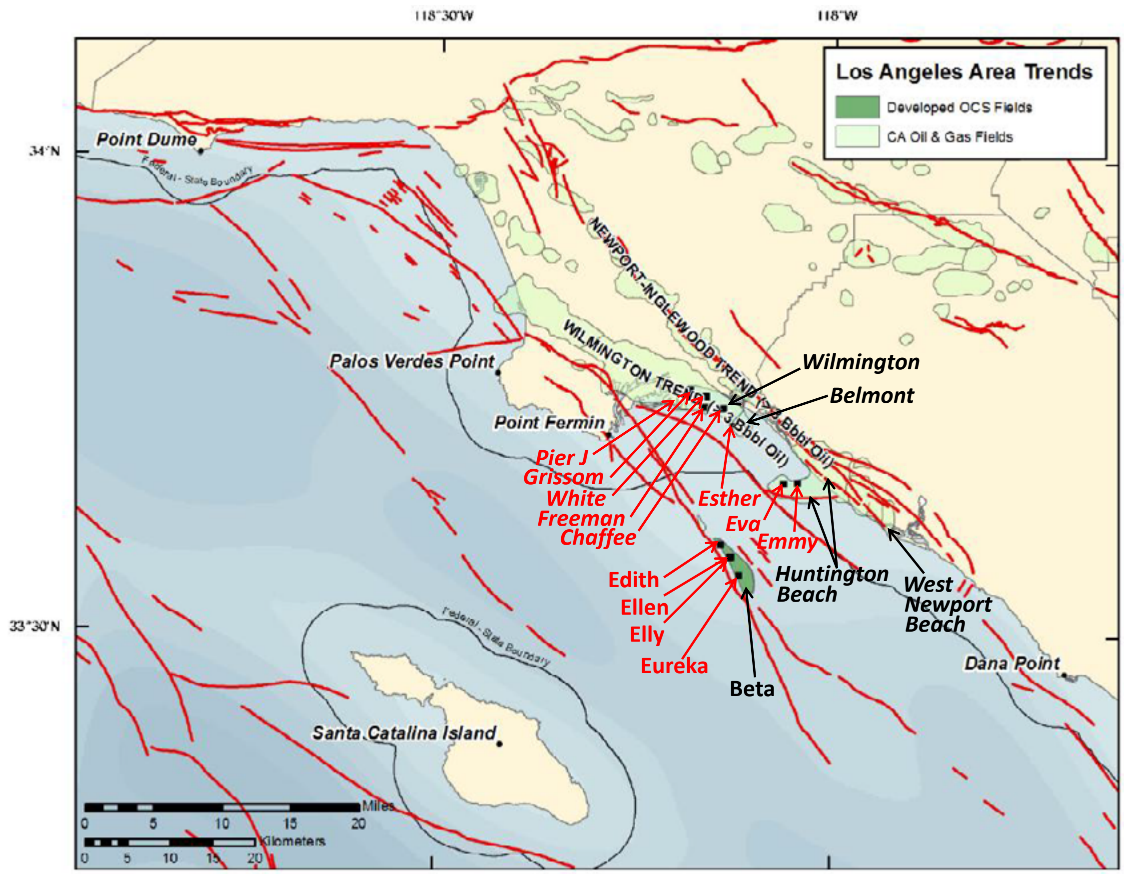


Figure 2.4-7. Operating oil fields and production facilities in the offshore Los Angeles Basin showing faults. Modified from BOEM (2014a). Black font labels with black arrows denote oil fields. Red font labels with red arrows denote offshore production facilities. Note that offshore production from the West Newport Beach field is performed using wells spud onshore. Production from the Huntington Beach field is performed from Platforms Eva and Emmy plus wells spud onshore. Facilities and field names in state waters are italicized.

Production statistics for the offshore Los Angeles Basin is given in Table 2.4-5. Annual production in 2013 for all of offshore California shows about 23% of the oil and 14%

of the gas is produced in the offshore Los Angeles Basin. About 80% of oil and gas production from this region comes from the Wilmington offshore oil field. Production is dominated by reservoirs in the middle Miocene and Pliocene turbidite sands. The undiscovered resources of the offshore Los Angeles Basin are expected to be found in sandstone reservoirs similar to those producing today. The production levels for the offshore Los Angeles Basin in 2013 are about 6.5% of the state onshore oil production and about 2.6% of the gas production.

Properties of the main producing reservoirs currently under production are given in Table 2.4-6. There are several reservoirs in which the reservoir depths are less than 1000 m (3280 ft); however, all of these shallow reservoirs have high permeabilities (> 100 md), which means that hydraulic fracturing is not likely to be essential for petroleum production. In all cases, reservoir permeabilities are in the millidarcy to darcy range. The API gravities show that the crude oils produced are mostly heavy to medium.

Table 2.4-5. Production and resource estimates for currently producing fields in the offshore Los Angeles Basin in 2013 (BOEM, 2013; DOGGR, 2010, 2011, 2012, 2013, 2014a).

Field*	Original Recoverable Reserves		Cumulative Production		Annual Production - 2013		Remaining Reserves	
	Oil, (m^3) x10^6 (bbl[#]) x10^6	Gas, (m^3) x10^6 (Mcf[##]) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Beta	18.1 (114)	1,040 (36.7)	15.4 (97.0)	889 (31.4)	0.240 (1.51)	10.5 (0.370)	2.67 (16.8)	150 (5.29)
Belmont	NA	NA	11.1 (69.8)	1,100 (39.0)	0.112 (0.702)	7.90 (0.279)	NA	NA
Huntington Beach	NA	NA	94.5 (595)	9,340 (330)	0.256 (1.61)	17.1 (0.604)	NA	NA
West Newport	10.5 (65.8)	256 (9.03)	10.1 (63.8)	238 (8.39)	0.00383 (24.1)	0.277 (0.00979)	0.316 (1.98)	18.0 (0.636)
Wilmington	NA	NA	24.9 (157)	1,420 (50.1)	1.55 (9.77)	95.2 (3.36)	NA	NA

** The Beta field is in federal waters. All other fields are in state waters.*

[#] bbl = oil barrel (one bbl = 42 gallons); [##] Mcf = one thousand cubic feet (one Mcf = 7481 gallons)

Table 2.4-6. Offshore Los Angeles Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993; DOGGR, 1992; Beyer, 1995).

Field	Formation	Epoch	Play	Average Depth (m)(ft)	Net Thickness (m)(ft)	Permeability (m^2) x 10^{15}	Porosity	API Gravity (o)
Beta	D	M	PFS	1,158 (3,800)	434 (1,420)	1 - 296	16 - 26	18
Belmont	RP	P/M	SSAOSL	899 (2,950)	30 (98)	963	30 - 33	16 – 27
Belmont	P	M	SSAOSL	1,219 (4,000)	8 (26)	234	34	23 – 29
Belmont	P	M	SSAOSL	1,676 (5,500)	76 (250)	177	20	23 – 29
Belmont	RP	P/M	SSAOSL	1,128 (3,700)	32 (100)	1617	35	21 – 30
Belmont	P	M	SSAOSL	1,219 (4,000)	46 (150)	725	31	23 – 29
Belmont	P	M	SSAOSL	1,463 (4,800)	26 (85)	493	31	23 – 29
Belmont	P	M	SSAOSL	1,646 (5,400)	61 (200)	138	25	25 – 28
Belmont	P	M	SSAOSL	1,859 (6,100)	23 (76)	79	25	25 – 28
Huntington Beach	RP	P	SSAOSL	460 (1,510)	27 (89)	987	34	15
Huntington Beach	P	M	SSAOSL	671 (2,200)	38 (120)	987	32	11 – 14
Huntington Beach	P	M	SSAOSL	732 (2,400)	58 (190)	296	25	17 – 18
Huntington Beach	P	M	SSAOSL	869 (2,850)	37 (120)	395 - 888	28	14 – 19
Huntington Beach	P	M	SSAOSL	1,097 (3,600)	76 (250)	89 - 166	21 - 24	22
Huntington Beach	P	M	SSAOSL	1,158 (3,800)	137 (449)	168 - 716	23 - 24	22
West Newport	P	M	SSAOSL	1,143 (3,750)	143 (469)	NA	NA	19
Wilmington	RP	P	SSAOSL	640 (2,100)	37 (120)	987	35	12 – 15
Wilmington	RP	P/M	SSAOSL	762 (2,500)	46 (150)	1253	32	12 – 25
Wilmington	P	M	SSAOSL	914 (3,000)	91 (300)	888	33	14 – 25
Wilmington	P	M	SSAOSL	1,097 (3,600)	112 (367)	459	27	25 – 30
Wilmington	P	M	SSAOSL	1,615 (5,300)	38 (120)	74	27	25 – 32
Wilmington	P	M	SSAOSL	1,981 (6,500)	91 (300)	74	23	28 – 32
Wilmington	P	M	SSAOSL	2,438 (8,000)	61 (200)	5	10	28 – 32
Wilmington	CS	LC	SSAOSL	2,591 (8,500)	5 (16)	5	10	28 – 32

Formations: D – Delmontian; RP - "Repetto" Puente; P – Puente; CS – Catalina Schist

Epoch: P – Pliocene; M – Miocene; LC – Late Cretaceous

Play: PFS – Puente Fan Sandstone; SSAOSL - Southwestern Shelf and Adjacent Offshore State Lands

2.4.4. Other Offshore Basins

Currently, petroleum production only occurs in three offshore sedimentary basins as described in Sections 2.4.1 through 2.4.3. Figure 2.4-1 shows 19 sedimentary basins for offshore California, which means that 16 additional basins have potential for oil and gas development. Information about the physical characteristics of petroleum reservoirs in these other offshore basins is very limited, although BOEM (2014a) has estimated reserves for all of these basins. However, as noted in Section 2.3, an offshore development ban in the 1969 in state waters and a moratorium in federal waters since the 1982 has slowed offshore development. Although the moratorium in federal waters ended in 2008, no offshore lease sales have occurred since that time.

As described in Volume I, Chapter 4, potentially more significant undiscovered or undeveloped conventional accumulations are expected to be present along the central and southern California coast. If these were developed, they would likely only involve the occasional use of well stimulation for their development, because the formations where oil is likely to be found typically do not require permeability enhancement. The development of these more easily produced resources would take priority over any low-permeability plays requiring routine well stimulation. Given the limited information available about petroleum resources and development in these other offshore basins, and the low level of offshore development activity since 1990, the focus of this case study is on well stimulation associated with current offshore production.

2.5 Offshore Production Operations and Well Stimulation

Offshore petroleum production operations and their use of well stimulation split into two categories: state waters and federal waters. The main difference for these two categories is the different regulatory environments for state and federal waters governing the disposition of well stimulation fluids. California disallows discharge of fluid into the ocean in state waters if it contains any hydrocarbon or other pollutants (California Public Resources Code Section 6873), whereas in federal waters, operators can discharge restricted quantities of hydrocarbons and certain other pollutants as specified in the NPDES permit. This section summarizes operational aspects of fluids handling, treatment, and discharge, and the use of well stimulation offshore in both federal and state waters.

The conduct of offshore well stimulation in general is described in Volume I, Chapter 2. Well stimulation fundamentally applies the same way offshore as onshore. The majority of onshore hydraulic fracturing in California helps to produce low-permeability diatomite reservoirs that have permeability on the order of 10^{-15} m^2. Most offshore reservoirs are significantly more permeable than this, as seen from Tables 2.4-2, 2.4-4, and 2.4-6. Hydraulic fracturing is not essential for production from more permeable reservoirs; this is consistent with historical information discussed below. Matrix acidizing is more commonly used for higher permeability systems and could have application offshore, but data concerning the use of matrix acidizing for operations in federal waters are currently not available.

Generally speaking, there are three types of fluids that need to be handled on an offshore platform or island: (1) aqueous; (2) hydrocarbon liquids; and (3) hydrocarbon gases. Aqueous fluids include produced water from the subsurface petroleum reservoir; well treatment, completion and workover fluids; water injection fluids (for waterflooding); some drilling muds; and other fluids such as cooling water. Hydrocarbon liquids and gases are the fluids produced by the reservoir, as well as some drilling muds that consist of hydrocarbon-based fluids. In some cases, operators inject hydrocarbon fluids as part of a strategy for recovering reservoir hydrocarbons. The quantity of fluids injected and produced typically exceeds the storage capacity on a platform. Therefore, fluids must be moved off the platform in one of the following four ways: (1) transported onshore; (2) injected into the subsurface environment; (3) discharged to the ocean; (4) flared, depending on the type of fluid. For example, the release of bulk (or free) hydrocarbon phases to the ocean is not permitted, and only volatile hydrocarbon gases may be flared, subject to permit restrictions.

2.5.1. Operations in Federal Waters

Federal waters are defined to be more than 5.6 km (3 geographical miles or about 3.5 miles) offshore according to the Submerged Lands Act of 1953 (Title 43 U.S. Code, Section 1312). The locations of federal offshore operations are shown in Figure 2.2-1 and in more detail in Figures 2.4-3 and 2.4-7, which also show the federal-state boundary. Table 2.5-1 provides information about the offshore facilities.

Platforms in federal waters lie 6 to 16.9 km (3.73 to 10.5 miles) from land in water depths ranging from 29 to 365 m (95.1 to 1200 ft). There are 15 to 96 slots on each platform, which are distinct sites on the platform deck available for drilling wells.

Table 2.5-1. Oil production facilities in Federal waters (BOEM, 2015b).

Platform	Operator**	Field	Distance to Land (km)(miles)	Location	Slots	Water Depth (m)(ft)	Date installed
A	DCOR	Dos Cuadras	9.3 (5.8)	Santa Barbara Basin	57	57.3 (188)	1968
B	DCOR	Dos Cuadras	9.2 (5.7)	Santa Barbara Basin	63	57.9 (190)	1968
C	DCOR	Dos Cuadras	9.2 (5.7)	Santa Barbara Basin	60	58.5 (192)	1977
Gilda	DCOR	Santa Clara	14.2 (8.8)	Santa Barbara Basin	96	62.5 (205)	1981
Gina	DCOR	Hueneme	6.0 (3.7)	Santa Barbara Basin	15	29.0 (95.0)	1980
Habitat	DCOR	Pitas Point	12.6 (7.8)	Santa Barbara Basin	24	88.4 (290)	1981
Henry	DCOR	Carpinteria	6.9 (4.3)	Santa Barbara Basin	24	52.7 (173)	1979
Hillhouse	DCOR	Dos Cuadras	8.9 (5.5)	Santa Barbara Basin	60	57.9 (190)	1969
Harmony	ExxonMobil	Hondo	10.3 (6.4)	Santa Barbara Basin	60	365 (1200)	1989
Heritage	ExxonMobil	Pescado/Sacate	13.2 (8.2)	Santa Barbara Basin	60	328 (1080)	1989
Hondo	ExxonMobil	Hondo	8.2 (5.1)	Santa Barbara Basin	28	257 (842)	1976
Hogan	POO	Carpinteria	6.0 (3.7)	Santa Barbara Basin	66	46.9 (154)	1967
Houchin	POO	Carpinteria	6.6 (4.1)	Santa Barbara Basin	60	49.7 (163)	1968
Gail	Venoco	Sockeye	15.9 (9.9)	Santa Barbara Basin	36	225 (739)	1987
Grace	Venoco	Santa Clara	16.9 (10.5)	Santa Barbara Basin	48	96.9 (318)	1979
Harvest	FMO&G	Point Arguello	10.8 (6.7)	Santa Maria Basin	50	206 (675)	1985
Hermosa	FMO&G	Point Arguello	10.9 (6.8)	Santa Maria Basin	48	184 (603)	1985
Hidalgo	FMO&G	Point Arguello/Rocky Point	9.5 (5.9)	Santa Maria Basin	56	131 (430)	1986
Irene	FMO&G	Point Pedernales	7.6 (4.7)	Santa Maria Basin	72	73.8 (242)	1985
Ellen	Beta	Beta	13.8 (8.6)	Offshore Los Angeles Basin	80	80.8 (265)	1980
Elly*	Beta	Beta	13.8 (8.6)	Offshore Los Angeles Basin	NA	77.7 (255)	1980
Eureka	Beta	Beta	14.5 (9.0)	Offshore Los Angeles Basin	60	213 (700)	1984
Edith	DCOR	Beta	13.7 (8.5)	Offshore Los Angeles Basin	72	49.1 (161)	1983

**Elly is a processing platform for production from Ellen and Eureka, not a production platform*

***FMO&G – Freeman McMoRan Oil and Gas, LLC; DCOR – Dos Cuadras Offshore Resources, LLC; POO – Pacific Operators Offshore, LLC; Beta – Beta Operating Company, LLC; Venoco – Venoco, Inc.; ExxonMobil – ExxonMobil Production Company*

2.5.1.1. Offshore Wells

The BOEM database (BOEM, 2015c) identifies 1370 offshore wells, but only 745 of these produced petroleum in 2013 (BOEM, 2015d). Generally the wells are not vertical but are directionally drilled with some component of horizontal offset. Directional drilling offshore California allows the wells to access laterally offset locations. (In unconventional shale reservoirs in the U.S. midcontinent, directional drilling has a different purpose. It increases the length of the production interval along a thin but horizontally extensive reservoir.) A recently drilled well (Well #SA-16) has the longest lateral reach, about 10,300 m (33,682 ft), of any well offshore California (Armstrong and Evans, 2011). This well, drilled from Platform Heritage, accesses the Sacate field (Figure 2.4-3). Figure 2.5-1 shows the well profile for Well #SA-16. As shown in Figure 2.5-1, the well does not have a long horizontal production interval, but drops angle to about 45 degrees through the producing zone. True vertical depths for the wells were not identified, but should roughly correspond to the reservoir depths given in Tables 2.4-2, 2.4-4, and 2.4-6.

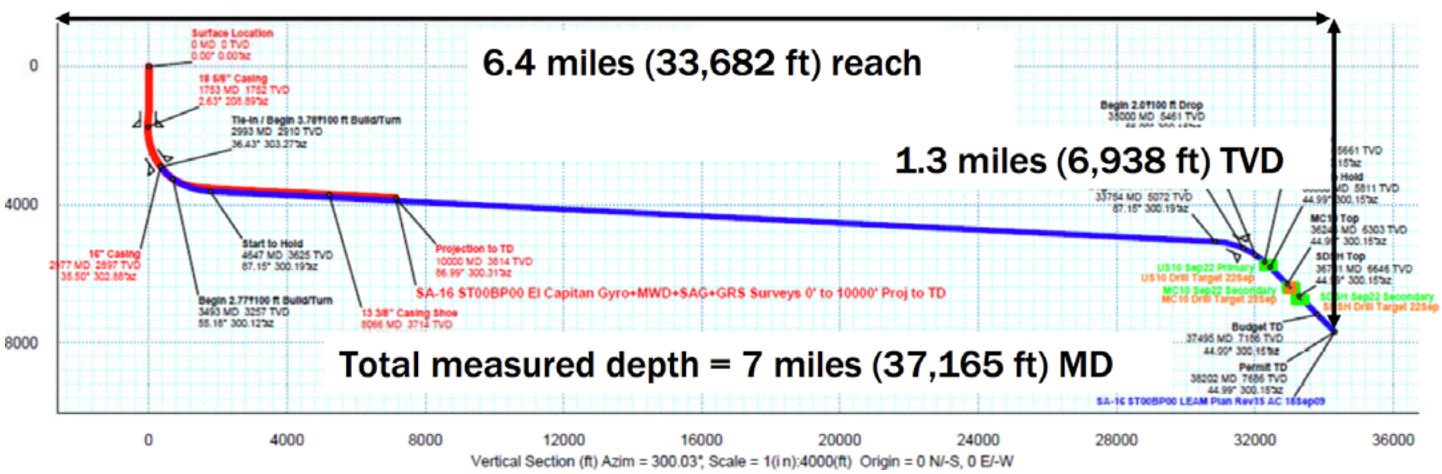


Figure 2.5-1. Well profile for #SA-16 extended reach well drilled from Platform Heritage into the Sacate oil field (modified from Armstrong and Evans, 2011).

2.5.1.2. Well Stimulation

No formal data collection system has been set up to track use of well stimulation conducted in federal waters. Estimates for hydraulic fracturing in federal waters have been made utilizing documents made available in response to requests under the Freedom of Information Act (FOIA) by various interested groups. These FOIA documents are available on the Bureau of Safety and Environmental Enforcement website (BSEE, 2015; see also Appendix A). However, they do not contain a concise listing of well stimulation activities, but rather an assortment of various types of draft and final documents, field reports, and e-mails with clues scattered throughout thousands of pages about well stimulation activities that were proposed or performed. Therefore, the estimation of past well stimulation activities can only provide an approximate idea about the level of activity. Tables 2.5-2 and 2.5-3 present the identified hydraulic fracturing and matrix acidizing treatments, respectively, identified from the records.

Table 2.5-2 shows 22 fracture treatments spanning a 22-year time frame, or about one fracture treatment per year on average. Some of the treatments involved multiple zones in the same well that are counted here as one treatment if performed in the same year. Hydraulic fractures conducted at Platform Hidalgo in the Point Arguello field were in fractured Monterey Shale and two at Platform Gail. The other treatments were mainly frac-packs in sandstones (Repetto and Sespe Formations). Fracturing fluid volumes from six of these treatments were identified in the FOIA documents; they ranged from 51.1 m^3 (13,500 gallons) to 303 m^3 (80,000 gallons), averaging about 121 m^3 (32,000 gallons). It is possible that not all such stimulations have been captured in the records obtained through FOIA simply because the records were not set up to ensure an accurate retrieval of this information. No other records or documents of hydraulic fracture stimulations in federal offshore waters beyond that obtained through FOIA have been identified. Despite this uncertainty, the information from the FOIA documents suggests that the level of hydraulic fracturing activity in federal waters is low.

Table 2.5-3 shows 12 matrix acidizing treatments identified in the FOIA documents for federal offshore waters over nearly 30 years. The FOIA requests tended to focus on hydraulic fracturing, with less emphasis on matrix acidizing. The FOIA documents clearly do not include all the matrix acidizing applications that have occurred. Thirty nine matrix acidizing treatments performed in 26 wells at the Point Arguello field in just a two-year period from 2000 through 2002 were reported by Patton et al. (2003), and none of these treatments was identified from the FOIA documents. Patton et al. (2003) indicated that the typical treatment volume was 55.8 m^3 (14,750 gallons), consisting of 7.57 m^3 (2,000 gallons) of 80%/20% hydrochloric acid (HCl) and xylene, 15.1 m^3 (4,000 gallons) of 12%/3% HCl/hydrofluoric (HF) mud acid, 21.8 m^3 (5,750 gallons) of ammonium chloride, and 11.4 m^3 (3,000 gallons) of a “foamed pill” for acid diversion. DOGGR has recently issued a draft regulation specifying a quantitative definition to distinguish matrix acidizing from other uses of acid for well maintenance (DOGGR, 2014b). Data from Patton et al. (2003) do not provide enough information to determine whether the acid treatments qualify as matrix acidizing or well cleanout. The data do suggest that operators perform acid treatments of some kind, not necessarily matrix acidizing, more frequently than hydraulic fracturing.

Table 2.5-2. Hydraulic fracturing in Federal offshore waters (BSEE, 2015).

API	Well	Lease	Operator	Platform	Field	Date
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1997
043112068200	E-11	P-0205	Venoco	Gail	Sockeye	1992
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2009
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2010
043112056101	S-60	P-0216	Nuevo/Torch	Gilda	Santa Clara	1994
043112063901	S-52	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112060501	S-53	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112063901	S-89	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112075400	S-87	P-0216	Nuevo/Torch	Gilda	Santa Clara	1997
043112063901	S-62	P-0216	Nuevo/Torch	Gilda	Santa Clara	1997
043112058201	S-28	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
043112061500	S-61	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
NA	S-68	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112063901	S-62	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112061601	S-65	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2003
043112068400	S-075	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013**
043112068100	S-071	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*
043112056800	S-033	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*
043112050100	S-005	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*

NA – not available

**applied for Categorical Exclusion Review*

***received approval based on Categorical Exclusion Review for treatment*

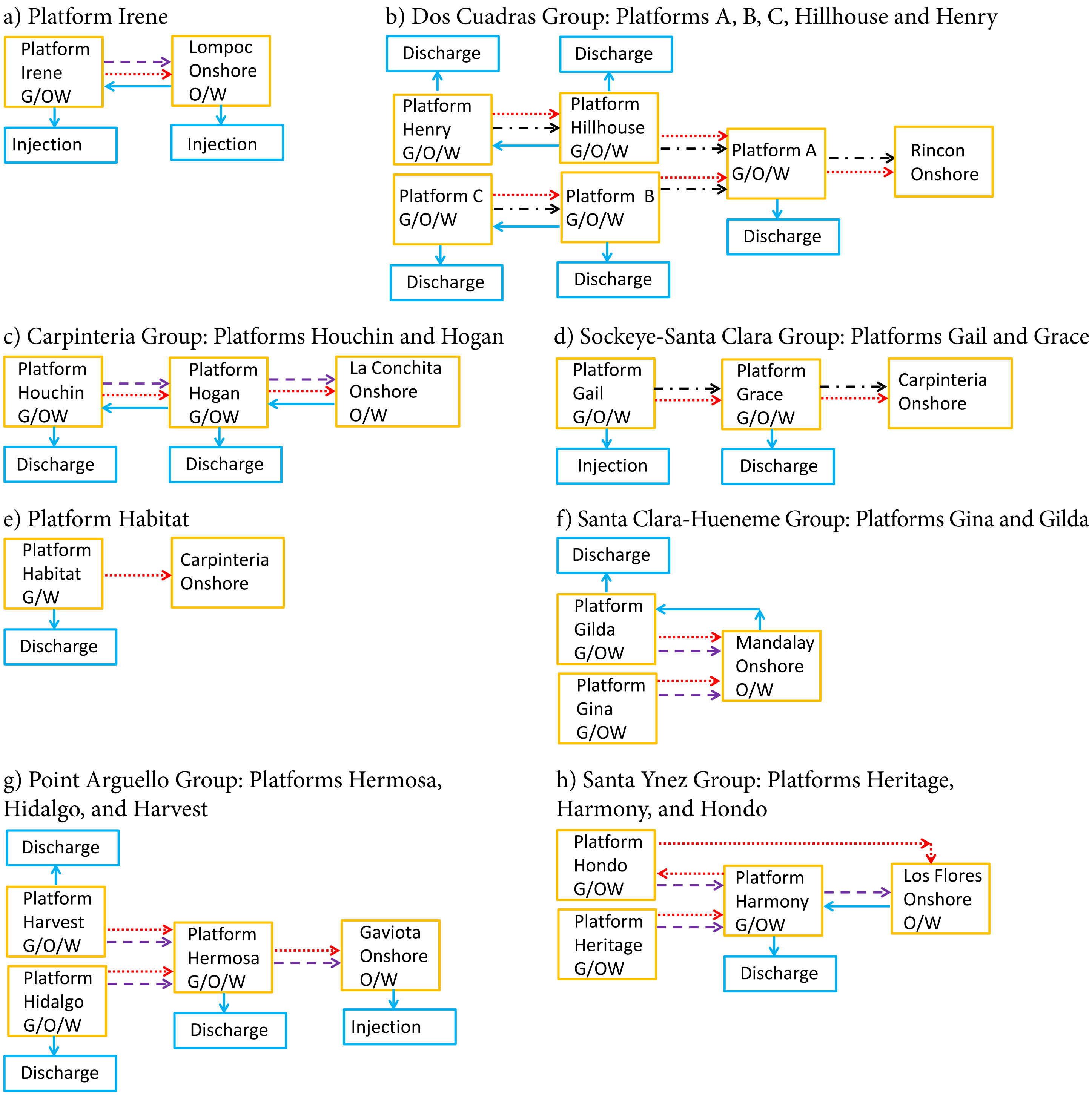
Table 2.5-3. Matrix acidizing in Federal offshore waters (BSEE, 2015).

API	Well	Lease	Operator	Platform	Field	Date
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1992
560452006500	C-4	P-0450	Chevron	Hidalgo	Point Arguello	1992
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1999
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2010
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	1985
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	1988
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112051300	S-07	P-0216	Nuevo/Torch	Gilda	Santa Clara	2002
043112054600	S-19	P-0216	Nuevo/Torch	Gilda	Santa Clara	2002
043112075400	S-87	P-0216	Nuevo/Torch	Gilda	Santa Clara	2011

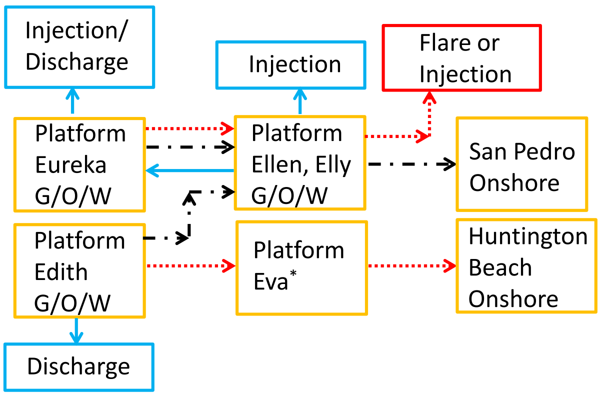
2.5.1.3. Fluids Handling

Pipelines transport fluids between facilities and between offshore and onshore locations. Pipelines exclusively transport oil and gas destined for sale onshore, with potential exceptions for temporary system breakdowns and delivery of well stimulation fluids to offshore facilities. Fluid handling includes separation of oil, gas, and produced water, and in some cases water treatment. Subject to restrictions of the NPDES permit, well stimulation fluids can be mixed with produced water for disposal, with potential impacts on the marine environment.

In several cases, the fluids-handling systems operate cooperatively for groups of platforms; each platform does not necessarily operate independently for delivery of oil and gas onshore and for produced water disposal. Figure 2.5-2 below shows the connections for transporting oil, gas, and water by platform groups that interact for fluids handing and the expected disposition of produced water disposal. Where one cell expands laterally to two cells, a separation is indicated (e.g., an oil/water mixture separated into bulk oil and water phases). Where two cells expand laterally into one cell, the fluid streams are combined.


a) Platform Irene
Platform Irene G/OW
Lompoc Onshore O/W
Injection
Injection
b) Dos Cuadras Group: Platforms A, B, C, Hillhouse and Henry
Discharge
Discharge
Platform Henry G/O/W
Platform Hillhouse G/O/W
Platform A G/O/W
Rincon Onshore
Platform C G/O/W
Platform B G/O/W
Discharge
Discharge
Discharge
c) Carpinteria Group: Platforms Houchin and Hogan
Platform Houchin G/OW
Platform Hogan G/OW
La Conchita Onshore O/W
Discharge
Discharge
d) Sockeye-Santa Clara Group: Platforms Gail and Grace
Platform Gail G/O/W
Platform Grace G/O/W
Carpinteria Onshore
Injection
Discharge
e) Platform Habitat
Platform Habitat G/W
Carpinteria Onshore
Discharge
f) Santa Clara-Hueneme Group: Platforms Gina and Gilda
Discharge
Platform Gilda G/OW
Mandalay Onshore O/W
Platform Gina G/OW
g) Point Arguello Group: Platforms Hermosa, Hidalgo, and Harvest
Discharge
Platform Harvest G/O/W
Platform Hermosa G/O/W
Gaviota Onshore O/W
Platform Hidalgo G/O/W
Discharge
Injection
Discharge
h) Santa Ynez Group: Platforms Heritage, Harmony, and Hondo
Platform Hondo G/OW
Platform Harmony G/OW
Los Flores Onshore O/W
Platform Heritage G/OW
Discharge

i) Beta Group: Platforms Ellen, Elly, Eureka, and Edith



*Eva is a platform in state waters – see Section 2.5.2

Figure 2.5-2. Fluids handling for offshore facilities in Federal waters (BOEM, 2014b). Separation process indicated by G/OW for gas separation only, G/O/W for gas/oil/water separation, O/W for oil water separation and G/W for gas/water separation. Blue solid lines designates water, red dotted lines for gas, black dash-dot lines for oil, purple dashed lines for water-oil mixtures, orange solid lines for facilities, and red solid lines for gas flaring/injection.

Platforms Irene, Ellen/Elly, and Gail are reported to inject 94% or more of their produced water (CCC, 2013) while the other platforms inject less than 15%. Therefore, in Figure 2.5-2, injection is indicated for Irene, Ellen/Elly, and Gail, and discharge is indicated for the others. For the Point Arguello and Beta groups in Figure 2.5-2g and 2.5-2i, some separation of oil and water is done on the platform and/or further oil/water separation could be done onshore.

In addition to gas, oil, and water that must be handled as a result of production, platforms use and typically discharge drilling muds to the ocean. Some platforms use cooling water, mainly to cool down gas after being compressed (Shah, 2013). In other cases, gas compression cooling is performed using air. Volumetrically, cooling water was found to be 86% of the total discharge to the ocean in a 2005 survey of offshore California platform discharges to the ocean (Lyon and Stein, 2010). Produced water represented the second largest discharge at 14%, and other discharges comprised than 1%.

While the description given here indicates the general ways in which operators handle fluids at the different offshore facilities, the specific modes of fluids handling may vary with time and conditions, especially where alternatives are available without requiring changes in permitting or infrastructure.

2.5.2. Operations in State Waters

State waters lie within 5.6 km (3 geographical miles or about 3.5 miles) offshore, according to the Submerged Lands Act of 1953 (Title 43 U.S. Code, Section 1312). Figure

2.2-1 above shows the locations of state offshore operations, and Figures 2.4-3 and 2.4-7 show these in more detail along with the federal-state boundary. Table 2.5-4 provides information about the offshore facilities. Platforms in state waters lie as far as 3.2 km (2.0 miles) from land in water depths ranging up to 64.3 m (211 ft).

Table 2.5-4. Oil production facilities in State waters (CSLC, 2008; 2009; 2010a; 2010b; 2012; 2013; Goleta, 2015).

Offshore Facility	Operator**	Field	Distance to Land (km)(miles)	Location	Slots	Water Depth (m)	Date installed
Platforms							
Holly	Venoco	South Elwood	3.2 (2.0)	Santa Barbara Basin	30	64.3 (211)	1966
Emmy	Occidental	Huntington Beach	1.9 (1.2)	Los Angeles Basin	52	14.3 (46.9)	1964
Eva	DCOR	Huntington Beach	2.9 (1.8)	Los Angeles Basin	37	17.4 (57.1)	1963
Esther	DCOR	Belmont	1.9 (1.2)	Los Angeles Basin	64	6.7 (22.0)	1990
Artificial Islands							
Rincon	Rincon LP	Rincon	0.8 (0.5)	Santa Barbara Basin	NA	13.4 (44.0)	1958
Grissom	Oxy LB	Wilmington	0.2 (0.1)	Los Angeles Basin	NA	12.2 (40.0)	1967
White	Oxy LB	Wilmington	0.7 (0.4)	Los Angeles Basin	NA	12.2 (40.0)	1967
Chaffee	Oxy LB	Wilmington and Belmont	1.3 (0.8)	Los Angeles Basin	NA	12.2 (40.0)	1967
Freeman	Oxy LB	Wilmington	2.0 (1.2)	Los Angeles Basin	NA	12.2 (40.0)	1967
Seafloor Completion							
Rincon	Rincon LP	Rincon	0.7 (0.4)	Santa Barbara Basin	N/A	16.8 (55.1)	1961
Onshore***							
West Montalvo	Hunter	West Montalvo	0	Santa Barbara Basin	N/A	N/A	NA
Huntington Beach	*	Huntington Beach	0	Los Angeles Basin	N/A	N/A	NA
West Newport	*	West Newport	0	Los Angeles Basin	N/A	N/A	NA

*NA – not available; N/A – not applicable; *Numerous operators; ** DCOR – Dos Cuadras Offshore Resources, LLC; Rincon LP, Rincon – Rincon Island Limited Partnership; Hunter - Hunter Oil and Gas, Inc. LLC; Venoco – Venoco, Inc.; Oxy LB – Oxy Long Beach; Occidental – Occidental Petroleum Corporation; *** Onshore - Onshore Well Locations for Offshore Production*

2.5.2.1. Offshore Wells

The DOGGR database identifies 1,972 active or idled offshore wells (DOGGR, 2015). As in federal waters, wells in state waters typically have some amount of lateral offset achieved with directional drilling (Section 2.5.1.1). As a result, true vertical depths were not identified in most cases, but should roughly correspond to the reservoir depths given in Tables 2.4-2, 2.4-4, and 2.4-6.

2.5.2.2 Well Stimulation

Records given in Appendix M, Volume I of this report allow evaluation of past use of well stimulation conducted in state waters. All of the offshore hydraulic fracturing in state waters has occurred on the THUMS islands and Platform Esther that operate in the Wilmington and Belmont fields. The data shows hydraulic fractures that were performed between January 2002 and December 2013. In total, operators conducted 117 hydraulic fracture treatments, with 106 conducted on the THUMS islands in the Wilmington field, 5 conducted on Island Chaffee (one of the THUMS islands) in the Belmont field “old area” and 6 conducted on Platform Esther in the Belmont field “surfside area.” No hydraulic fracturing was reported from facilities in state waters in the Santa Barbara Channel or from Platforms Eva and Emmy in the Los Angeles Basin. Treatment volumes for 19 stimulations conducted on the THUMS islands were recorded. The volumes ranged from 114 to 803 m^3 (30,000 to 212,000 gallons) of stimulation fluids, with an average of 530 m^3 (140,000 gallons). It is not known whether these stimulations used fresh water or seawater.

Only the South Coast Air Quality Management District has records that include matrix acidizing information for facilities in state waters in the Los Angeles Basin. This data shows that from June 2013 to April 2014 there were 135 acid treatments offshore, with 111 on the THUMS islands, 17 on Pier J, and 7 at Huntington Beach for wells that extend offshore. Treatment volumes ranged from 12.5 to 319 m^3 (3,300 to 84,300 gallons), with an average of 15,900 gallons. However, these treatments may not meet the matrix acidizing thresholds established by DOGGR per Senate Bill 4. The average treatment volume is close to the average treatment volume of 60.2 m^3 (14,750 gallons) reported by Patton et al. (2003) for acidizing in federal offshore waters at the Point Arguello field (see Section 2.5.1.2). Given the limited coverage for acid treatments, the numbers reported here strongly suggest that acid treatments (including both well cleanout and matrix acidizing) are performed more frequently than hydraulic fracturing.

2.5.2.3. Fluids Handling

As in federal waters, pipelines transport fluids between facilities and between offshore and onshore, separation of oil, gas, and produced water, and in some cases water treatment. Pipelines exclusively transport oil and gas destined for sale onshore, with potential exceptions for temporary system breakdowns and delivery of well stimulation fluids to offshore facilities. Fluid handling includes separation of oil, gas, and produced water, and in some cases water treatment.

Disposal of produced water for facilities in state waters is mainly done by injection into the reservoir, with some disposal onshore. Figure 2.5-3 shows the connections for transporting oil, gas, and water by platform groups that interact for fluids handing and the expected disposition of produced water disposal. Where one cell expands laterally to two cells, a separation is indicated (e.g., an oil/water mixture separated into bulk oil and water phases). Where two cells expand laterally into one cell, the fluid streams are combined.

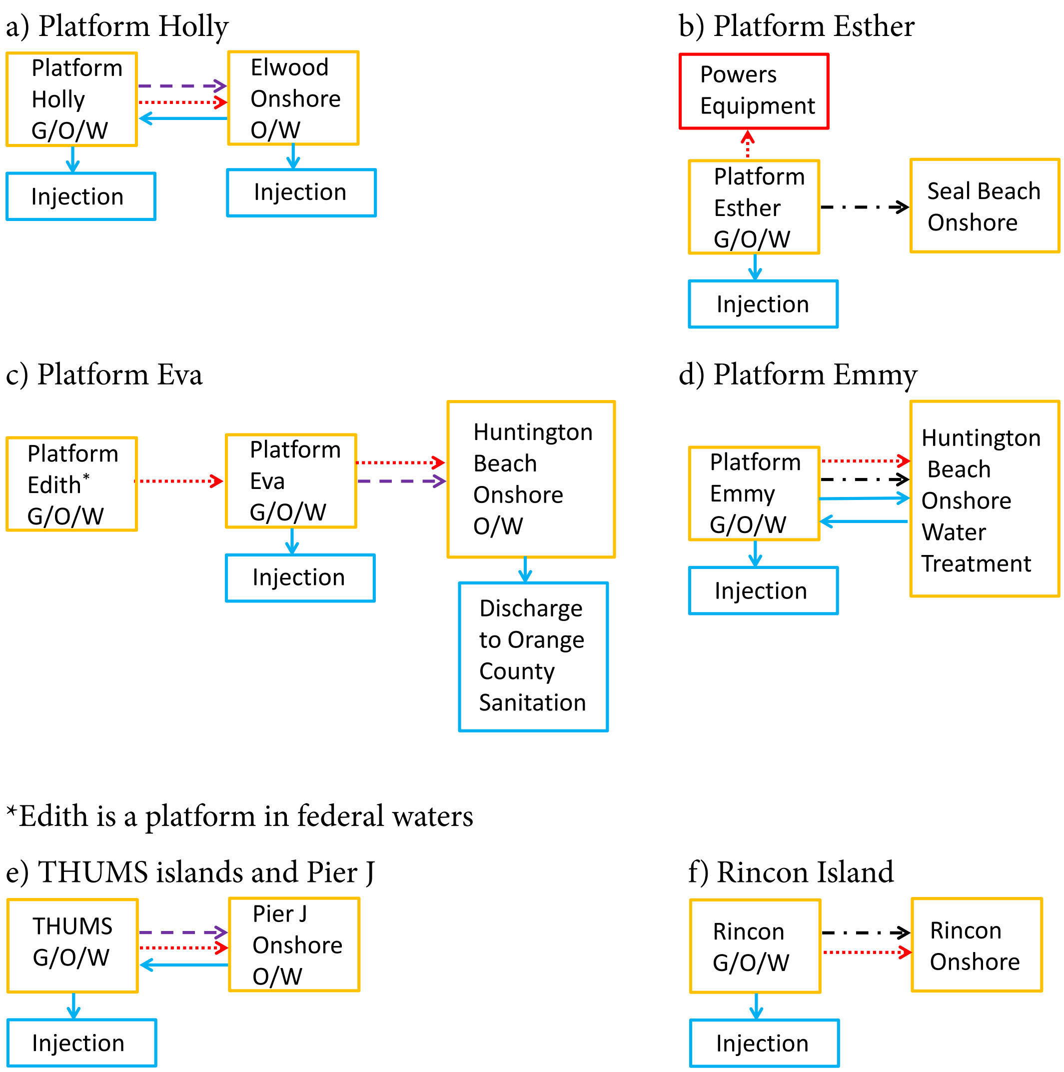


Figure 2.5-3. Fluids handling for offshore facilities in State waters (CSLC, 2008; 2009; 2010a; 2010b; 2012; 2013; Santa Barbara, 2011). Separation process indicated by G/OW for gas separation only, G/O/W for gas/oil/water separation, O/W for oil water separation and G/W for gas/water separation. Blue solid lines designates water, red dotted lines for gas, black dash-dot lines for oil, and purple dashed lines for water-oil mixtures, orange solid lines for facilities, and red solid lines for gas use in powering operations.

For the Holly (Figure 2.5-3a), Eva (Figure 2.5-3c), Emmy (Figure 2.5-3d), and THUMS (Figure 2.5-3e), some separation of oil and water is done on the platform, and further oil/water separation can be done onshore, which is either injected onshore, discharged into a sanitary sewer, or sent back offshore for injection. Therefore, the table shows water discharge from the platform with oil/water mixtures still sent onshore. Rincon produced water is injected into disposal wells on Rincon Island.

2.6. Ocean Discharge and Atmospheric Emissions

Environmental impacts from any activity are often connected to some type of discharge or emission of a material or possibly energy (e.g., heat, sound, light). This section focuses on intentional discharges to the ocean and atmospheric emissions, but also provides some discussion of accidental releases. In general, it is difficult to separate impacts from overall oil and gas operations from those directly associated with well stimulation. For this reason, many of the impacts discussed are based on oil and gas operations overall, with the recognition that well stimulation is only applied to a small, but difficult to quantify, subset of the producing wells.

2.6.1. Ocean Discharge from Offshore Facilities

As discussed in Section 2.5, intentional discharge to the ocean is only allowed at facilities in federal waters. Ocean discharge from offshore California operations in federal waters is regulated by the U.S. EPA under the NPDES permit CAG280000 (U.S. EPA, 2013a). This permit sets up specific limits for the types and quantities of materials that may be discharged to the ocean, as well as the ways in which the discharge is monitored. The results of the monitoring are recorded in discharge monitoring reports (DMRs) for each offshore facility. In Section 2.6.1.1, the permit limitations and monitoring requirements are summarized. The DMR information is summarized in Section 2.6.1.2.

2.6.1.1. NPDES Permit CAG280000

NPDES permit number CAG280000 covers the following categories of discharge: (1) drilling fluid and cuttings; (2) produced water; (3) well treatment, completion, and workover fluids; (4) deck drainage; (5) domestic and sanitary wastes; and (6) 17 miscellaneous other discharge categories, including noncontact cooling water and water-flooding discharges. The most recent general permit was reissued on March 1, 2014, and replaces the previous general permit; also, permit number CAG280000, issued on September 22, 2004 (U.S. EPA, 2013b), is applicable through February 28, 2019 (U.S. EPA, 2013a) and applies to all 23 platforms in federal waters.

Well stimulation fluids fall under well treatment, completion, and workover fluids (collectively called TCW fluids). For TCW discharge, the permit disallows any free oil discharge and restricts the amount of oil and grease in the discharge to 42 mg/L maximum and 29 mg/L monthly average. The permit does not restrict the volume of

TCW fluids that can be discharged per se, but specifically provides for discharge of these fluids mixed with produced water under the restrictions for produced water discharge. Although the NPDES permit covers well stimulation under the TCW category, it does not specifically refer to acidizing, and hydraulic fracturing is only mentioned in its section on definitions for the term “produced sands.” Consequently, the NPDES permit governing ocean discharges from oil platforms in federal waters does not specifically account for stimulation chemicals or their potential impact on the marine environment.

Some earlier EPA documents discuss fracturing and acidizing in the context of offshore effluent limitations and general information about typical additives (U.S. EPA, 1993; 1995; 1996). In particular, U.S. EPA (1993) provides a chemical analysis of an acidizing fluid used at THUMS and metals content of a California fracturing fluid. The following conclusion by U.S. EPA (1995) provides the basis for the current NPDES permit strategy for well treatment, completion, and workover fluids: “EPA has determined, moreover, it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water waste stream and take on the same characteristics of produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use, EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease and/or free oil in the Coastal Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.” The “previous discussion” referred to a statement (U.S. EPA, 1995) that “oil and grease serves as an indicator for toxic pollutants in the produced water waste stream which includes phenol, naphthalene, ethyl benzene, and toluene.” This list of toxic substances of concern does not include toxic substances used in stimulation treatments, nor does it provide justification for oil and grease being an effective indicator of the presence or absence of stimulation chemicals.

More complex requirements for produced water vary from platform to platform, as shown in Table 2.6-1, where “S” indicates a sampling requirement and specific concentration limits are indicated by numerical values. Where the NPDES permit requires sampling but no specific limit is given, the limits given in Table 2.6-2 apply. The last six facilities in Table 2.6-1 must comply with all the restrictions imposed by Table 2.6-2. All facilities must conform with a uniform requirement for oil and grease concentrations in produced water identical to the discharge limits quoted above for TCW fluids.

The limits in Table 2.6-1 and 2.6-2 are based on the Best Conventional Pollutant Control Technology (BCT) and the Best Available Treatment Economically Achievable (BAT) as originally published by the U.S. EPA in the Federal Register (FR, 1993) The limits also rely on an analysis of the Ocean Discharge Criteria, section 403(c) of the Clean Water Act (1972) (see also 33 USC §1343), assuming BCT and BAT are in place (CCC, 2013).

The NPDES permit provides additional detail concerning sampling frequency and method of collection. Concentrations in the measured effluent are reduced by a site-specific dilution factor that corresponds to a point with a 100 m lateral offset from the discharge release point. The diluted concentration is then compared with the concentration limits in the permit. Dilution factors for offshore California platforms have been found to range from 467:1 to 2,481:1 (MMS, 2001).

Table 2.6-1. NPDES produced water limits for all platforms; constituent sampling requirements and concentration limits for some platforms (U.S. EPA, 2013a)

Platform	Annual Discharge Limit (m^3) x10^6 (bbl#)x10^6	Amn	Copr	Benz	BzA	BzP	BzkF	BzbF	Chry	DBzA	USulf	Znc	HC
A	2.09 (13.140)		S			S	S	S					
B	2.61 (16.425)					S	S	S					
Edith	0.522 (3.285)											S	
Elly***	1.74 (10.950)											S	
Gail	0.696 (4.380)			S		S					5.79 1.67		
Gilda	4.05 (25.500)		S		S	S	S	S	S	S	5.79 1.39		
Gina	*	S	S			S	S	S					
Habitat	0.261(1.6425)		S	S		S	S	S		S	S		
Harmony, Heritage, Hondo**	5.37 (33.7625)												
Harvest	5.22 (32.850)	S	S	22 5.9	S	S	S	S	S	S	S		
Hermosa	6.40 (40.250)		S	S	S	S	S	S	S	S	5.77 4.9		
Hidalgo	2.90 (18.250)			S			S	S	S		S		
Hillhouse	1.16 (7.300)				S	S	S	S	S	S			
Hogan	2.21 (13.900)		S	17.6 5.9		S	S	S		S			S
#C	2.09 (13.140)												
#Eureka	***												
#Grace	0.348 (2.190)												
#Henry	1.04 (6.570)												
#Houchin	2.21 (13.900)												
#Irene	8.88 (55.845)												

*Limits for Amn, Copr, Benz, BzA, BzP, BzkF, BzbF, Chry, DBzA, USulf, Znc, and HC are in μg/L. #bbl=oil barrel (42 gallons) * Limit given for Gilda is a combined limit for both Gina and Gilda. **Discharge for these platforms are combined and discharged from Platform Harmony. ***Limit for Elly is for combined discharge with Ellen and Eureka. #Limits on chemical constituents discharged in produced water are given in Table 2.6-2 for these platforms. Amn = Ammonia, Copr = Copper, Benz = Benzene, BzA = Benzo (a) Anthracene, BzP = Benzo (a) Pyrene, BzkF = Benzo (k) Fluoranthene, BzbF = Benzo (b) Fluoranthene, Chry = Chrysene, DBzA = Dibenzo (a,h) Anthracene, USulf = Undissolved Sufides, Znc = Zinc, HC = Hexavalent Chromium. "S" denotes a requirement to measure without any specified limits. Quantified limits are given as maximum daily value – upper number; average monthly value – lower number.*

In addition to total discharge and chemical concentration limits, the NPDES permit also specifies quarterly whole effluent toxicity (WET) tests for produced water. These tests are conducted to estimate the chronic toxicity of produced water. WET tests are conducted for the following species:

- Red abalone, *Haliotis rufescens*, larval development test
- Giant kelp, *Macrocystis pyrifera*, germination and germ-tube length tests
- Topsmelt, *Atherinops affinis*, larval survival and growth tests

Various triggers and effluent limits are defined for the different tests, and testing requirements and frequency are modified by the test results. For example, consistent passing scores for the WET tests lead to reduced testing frequency. The tests are only performed for the following platforms: A, B, Edith, Elly, Gail, Gilda, Gina, Habitat, Harmony, Harvest, Hermosa, Hidalgo, Hillhouse, and Hogan. So nine platforms, C, Henry, Houchin, Ellen, Eureka, Grace, Irene, Hondo, and Heritage are not tested. As stated previously, all discharge for the Santa Ynez group, platforms Harmony, Hondo, and Heritage, is released from platform Harmony. It appears that discharge from platforms Ellen and Eureka are combined with Elly. Platform Irene does not discharge to the ocean at this time. The reasons for not performing WET tests for platforms C, Henry, Houchin, and Grace are not clear. As discussed in Section 2.5.1.2, the historical record indicates that hydraulic fracturing has only been used on platforms Gilda, Gail, and Hidalgo.

Another observation is that the more extensive tests required for produced water, including chemical constituent and toxicity tests and limits, do not apply to TCW fluids if they are not mixed with produced water for discharge. Also, because of the transient nature of well stimulation discharge, the WET tests may not capture toxicity effects from well stimulation fluid discharge if the tests are not conducted at the time of the discharge. However, the timing of WET tests is not linked to well stimulation events in the NPDES permit.

Table 2.6-2. NPDES constituent concentration limits for platforms for which limits were not specified in Table 2.6-1 (U.S. EPA, 2013a).

Constituent	Limit (µg/L)
Ammonia	1300/600; 2400
Arsenic	36/8; 32
Cadmium	8.8/1; 4
Copper	3.1/3; 12
Cyanide	1/1; 4
Lead	8.1/2; 8
Manganese	100; NA

Mercury	0.051/0.04; 0.16
Nickel	8.2/5; 20
Selenium	71/15; 60
Silver	1.9/0.7; 2.8
Zinc	81/20; 80
Benzene	5.9
Benzo (a) Anthracene	0.018; NA
Benzo (a) Pyrene	0.018; 3
Chrysene	0.018; NA
Benzo (k) Fluoranthene	0.018; NA
Benzo (b) Fluoranthene	0.018; NA
Dibenzo (a,h) Anthracene	0.018; NA
Hexavalent Chromium	50/2
Phenol	1,700,000; 120
Toluene	15,000; 50
Ethylbenzene	2,100; 4.3
2,4-Dimethylphenol	850; none
Undissociated Sufides	5.79; NA
Napthalene	none; 23.5
Total Chromium	NA; 8
Bis (2-ethylhexyl) phthalate	NA; 3.5

The limits for all platforms are the numbers preceding the semicolon. Limits following the semicolon are for platform Irene. Limits separated by a "/" represent differing federal and state limits, respectively. The most stringent limits are applied where conflicting limits exist. NA – limit not applicable; "none" means constituent was listed without a limit.

2.6.1.2. NPDES Discharge Monitor Reports

The historical discharge quantities and testing results stipulated by the NPDES permit are recorded in the U.S. EPA's Integrated Compliance Information System and Permit Compliance System database (ICIS/PCS) (U.S. EPA, 2015a). The database at present contains discharge data for some but not all of the platforms. The platforms and their data status are given in Table 2.6-3. Only 9 of the 23 platforms have data. Table 2.6-4 shows the 6 platforms with complete produced water flow records for 2012 through 2014. In general, the actual produced water discharges are significantly lower than the NPDES permit limits. Oil and grease are regularly measured and exceeded the limit in two instances. Values for ammonia, copper, undissociated sulfides, and zinc remained within the discharge limits. Measurements of Benzo (a) Anthracene, Benzo (a) Pyrene, Benzo (k) Fluoranthene, Benzo (b) Fluoranthene, Chrysene, Dibenzo (a,h) Anthracene are required for many of the platforms listed in Table 2.6-4, but no measurements were reported in the DMRs. WET tests are reported on a pass/fail basis; all test results in the DMRs have been reported as "pass." The DMRs do not track the quantity or composition of any specific constituents associated with well stimulation flowback fluids.

Table 2.6-3. Discharge monitoring report status (U.S. EPA, 2015a).

Platform	Facility-specific NPDES number	Data Status
A	CAF001156	Data – 2011 - 2014
B	CAF001157	Data – 2011 - 2014
C	CAF001300	Data – 2011 - 2014
Edith	CAF001150	Data – 2011 - 2014
Ellen	CAF001147	No data
Elly	CAF001148	No data
Eureka	CAF001149	No data
Gail	CAF000002	No data
Gilda	CAF001152	Data – 2011 - 2014
Gina	CAF001151	Data – 2011 - 2014
Grace	CAF000005	No data
Habitat	CAF001304	Data – 2011 - 2014
Harmony	CAF000006	No data
Harvest	CAF001305	No data
Henry	CAF001301	Data – 2011 - 2014
Heritage	CAF000007	No data
Hermosa	CAF001306	No data
Hidalgo	CAF001307	No data
Hillhouse	CAF001154	Data – 2011 - 2014
Hogan	CAF000003	No data
Hondo	CAF001302	No data
Houchin	CAF000004	No data
Irene	CAF001153	No data

Table 2.6-4. DMR values for produced water discharge and constituent concentrations (U.S. EPA, 2015a).

Platform	Annual Produced Water Flow (m³) x10⁶ (#bbl) x10⁶	Annual Produced Water NPDES Limit (m³) x10⁶ (bbl) x10⁶	Oil and grease (mg/L)	Ammonia (µg/L)	Copper (µg/L)	Undissociated sulfides (µg/L)	Zinc (µg/L)
A – 2014	0.248 (1.559)	2.09 (13.140)	40	NA	NM	NA	NA
A – 2013	0.373 (2.345)		62	NA	2.01	NA	NA
A – 2012	0.187 (1.177)		20	NA	2.01	NA	NA
B – 2014	0.348 (2.188)	2.61 (16.425)	29.3	NA	NA	NA	NA
B – 2013	0.267 (1.682)		28	NA	NA	NA	NA
B – 2012	0.368 (2.317)		42	NA	NA	NA	NA
Edith – 2014	0.0382 (0.240)	0.522 (3.285)	11.3	NA	NA	NA	8
Edith – 2013	0.0266 (0.1670		16.5	NA	NA	NA	8.008
Edith – 2012	0.0499 (0.314)		46.6	NA	NA	NA	8.1
Gilda – 2014	0.354 (2.227)	4.05 (25.500)	39	NA	2	0.82	NA
Gilda – 2013	0.318 (1.999)		19	NA	2.01	0.73	NA
Gilda – 2012	0.369 (2.321)		20	NA	2	0.48	NA
Gina – 2014	0.118 (0.740)		25	24.83	2	NA	NA
Gina – 2013	0.809 (0.509)		27	26.55	2.01	NA	NA
Gina – 2012	0.0585 (0.368)		20	39.13	2	NA	NA
Hillhouse – 2014	0.370 (2.327)	1.16 (7.300)	14	NA	NA	NA	NA
Hillhouse – 2013	0.454 (2.856)		18	NA	NA	NA	NA
Hillhouse – 2012	0.431 (2.709)		21	NA	NA	NA	NA
Limits	NA	NA	42	600	3	5.79	20

Concentrations are maximum measured values; limits are maximum daily values;

NA – not applicable; NM – no measurement; #bbl=oil barrel (one barrel = 42 gallons)

Lyon and Stein (2010) reported on the results of a 2005 special monitoring study for offshore California discharge into federal waters as part of a "reasonable potential analysis" for the EPA. This study provided a more comprehensive data set (but just for 2005) than available from the current DMRs, with measurements for all of the platforms in federal waters. A complete set of measurements was made for all the constituents in Table 2.6-2 plus undissociated sulfides, with the exception of one or two constituents at three platforms.

In summary, the NPDES permit provides protection against contamination expected from hydrocarbons and produced water. However, for well stimulation fluid flowback, it relies on an assumption that dilution, exposure, and toxicity for any different chemicals present in the discharge are sufficiently similar to those in petroleum fluids and produced water to prevent adverse impacts.

2.6.1.3. Offshore Spills

Spills in federal waters associated with offshore oil and gas exploration and production have been recorded by the BOEM. In general, the database displays spills of crude oil and or other chemicals, but the material most often released by accident is crude oil. When looking only at spills in federal waters offshore California, all but two of the 16 recorded spills of 10 barrels or more is crude oil (Table 2.6-5). In terms of spill volume, the 1969 Santa Barbara oil spill represents 98% of the releases over a 40-plus year record (see Section 2.3.3). Accidental releases of well stimulation fluids have not been reported. Despite the relatively small quantities of spills since the 1969 oil spill, events such as the 2010 Macondo blowout in the Gulf of Mexico and similar major oil spills elsewhere have influenced the current regulatory climate for offshore California oil and gas development.

Table 2.6-5. Offshore California spills in federal waters from oil and gas exploration and production (BOEM, 2015e).

Date	Facility	Spill Volume (m^3) (bbl)	Product(s) Spilled	Operation
1969-01-28	Platform A	12,700 (80000)	crude oil	Drilling
1969-12-16	Platform C	143 (900)	crude oil	Pipeline
1981-08-24	Platform Ellen	2.7 (17)	crude oil	Production
1981-09-13	Platform Henry	1.6 (10)	crude oil	Production
1981-10-23	Platform Henry	1.6 (10)	diesel	Production
1981-10-24	Platform Elly	2.7 (17)	crude oil	Production

1984-07-19	Rig Diamond M. Eagle	4.9 (31)	crude oil	Abandonment
1987-11-25	Platform Hondo	3.2 (20)	crude oil	Pipeline
1990-05-07	Plat Habitat	16 (100)	16 m^3 (100 bbl) mineral oil in 22.9 m^3 (144 bbl) of oil-based mud	Drilling
1991-05-10	Plat Gina	7.9 (50)	crude oil	Pipeline/Motor Vessel
1991-11-21	Platform C	1.6 (10)	crude oil	Production
1994-05-25	Plat Hondo	4.8 (30)	crude oil	Production
1994-12-17	Plat Hogan	7.9 (50)	crude oil	Production
1996-05-01	Plat Heritage	23.8 (150)	crude oil	Pipeline
1999-06-05	Platform Eureka	1.6 (10)	crude oil	Pipeline
2008-12-07	Platform A	4.8 (30)	crude oil	Production

Note: Database for spills > 50 bbl covers years 1964 through 2011.

Database for spills between 10 and 50 bbl covers years 1970 through 2011. #bbl=oil barrel (one barrel = 42 gallons)

A California Office of Emergency Services (19 CCR 2703(a)) database of spills from 2009 through 2014 also records about 170 spill incidents offshore. The database covers facilities in both state and federal waters. The spill reports generally involve small or unknown quantities, with the largest quantified spill occurring on platform Eva on 1/6/2009. This spill of 1.3 m^3 (8 barrels) of drilling mud on the platform resulted in about 0.02 m^3 (0.14 barrels) being released into the ocean. No reports specifically identified spills of well stimulation fluids.

Unintentional release in connection with hydraulic fracturing can also occur if the hydraulic fracture extends out of zone and provides a leakage pathway to the sea floor. Fracture height is limited by natural boundaries, stresses, leakoff, and volume of injection (see Volume I, Chapter 2). The maximum fracture height observed in hydraulic fracturing operations is 588 m (1,930 ft) in the Barnett shale in Texas. The statistics of observed fracture heights show that only 1% exceeds 350 m (1,150 ft). Reservoir depths from Tables 2.4-2, 2.4-4, and 2.4.6 are all greater than 350 m (1,150 ft), and only two are less than 588 m (1930 ft), Dos Cuadras at 488 m (1,600 ft) depth and the shallowest reservoir in the Huntington Beach field at 460 m (1,510 ft) depth. Both of these reservoirs have high permeability (Dos Cuadras, 49-987 md; Huntington Beach shallowest reservoir, 987 md) making the use of hydraulic fracturing less likely. Furthermore, there are no reports of hydraulic fracturing having been used in these reservoirs. Therefore, the possibility of a spill caused by hydraulic fracturing between a reservoir and the ocean floor appears to be remote.

2.6.2. Atmospheric Emissions from Offshore Facilities

Offshore facility operations incur emissions of air pollutants and greenhouse gases (GHGs). Intentional emissions include combustion products. Unintentional emissions result from process inefficiencies such as fugitive methane releases from natural gas production. The primary pollutants are nitrous oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM). Other pollutants are grouped into the classification of hazardous air pollutants (HAPs), which include some VOCs but also other items such as crystalline silica, hydrochloric acid, and methanol. GHGs include carbon dioxide (CO_2), methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), VOCs, and black carbon.

The emissions estimates in this case are done for all offshore facilities as a group. Unlike the ocean discharge issue, there is no significant distinction in air emissions discharge handling between facilities in state and federal waters. The fraction of air emissions caused by well stimulation activities is not available, but is expected to be a small fraction of the overall emissions for oil and gas activities.

2.6.2.1. Air Pollutant Emission Estimates

Specific air pollutant emission estimates for each offshore facility were obtained from the California Air Resources Board (CARB, 2015a) database for 2012. These consist of the following criteria pollutants that comprise the major components of air pollution: total organic gases (TOG), reactive organic gases (ROG), carbon monoxide (CO), nitrous oxides (NOX), sulfur oxides (SOX), particulate matter (PM), particulate matter less than 10 microns in diameter (PM10); particulate matter less than 2.5 microns in diameter (PM2.5). The emissions are available by offshore facility. Table 2.6-6 shows the summary of mass emissions grouped for the Santa Maria and Santa Barbara Basins and the offshore Los Angeles Basin. This does not include air emissions from onshore wells that reach offshore. As discussed in Section 2.7.2.1, these emissions are typically a small fraction of the overall emissions in the corresponding air basins.

Table 2.6-6. Criteria pollutant emissions (metric tons (lbs), 2012) (CARB, 2015a).

Region	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
Santa Barbara and Santa Maria Basins	912 (2,010,000)	471 (1,040,000)	346 (763,000)	368 (811,000)	100 (221,000)	51.7 (114,000)	50.9 (112,000)	49.0 (108,000)
Offshore Los Angeles Basin	113 (250,000)	58.0 (128,000)	29.3 (64,600)	219 (484,000)	0.1 (220)	6.9 (15,200)	6.7 (14,800)	6.7 (14,800)
Total	1,030 (2,260,000)	529 (1,170,000)	375 (827,000)	587 (1,290,000)	100 (221,000)	58.6 (129,000)	57.6 (127,000)	55.7 (123,000)

In addition, numerous toxic pollutant emissions are reported (Table 2.6-7). Toxic air pollutants are substances that have a direct adverse health effect and are known or suspected of being carcinogens, endocrine disruptors, or cause other serious health effects. Common toxic pollutants to both regions include 1,3-Butadiene, arsenic, benzene, cadmium, formaldehyde, lead, methylene chloride, ammonia (NH_3), naphthalene, nickel, and polycyclic aromatic hydrocarbons (PAHs). Toxic air pollutant emissions in Table 2.6-7 are from CARB's 2012 emissions inventory, but these emissions are not tabulated for each year and may be estimated from data over a range of years.

Air emissions resulting directly from well stimulation have not been reported; however, these are presumably included in the total emissions given in Tables 2.6-6 and 2.6-7, and are expected to represent a small percentage of the overall air emissions.

Table 2.6-7. Toxic air pollutant emissions (kg/yr (lbs/yr), 2012) (CARB, 2015a).

Toxic pollutant	Santa Maria and Santa Barbara Basins	Offshore Los Angeles Basin	Total
1,3-Butadiene	392 (863)	250 (551)	642 (1,410)
2MeNaphthalene	0.00	0.48 (1.1)	0.48 (1.1)
Acenaphthene	0.00	0.02 (0.04)	0.02 (0.04)
Acenaphthylene	2,370 (5,230)	0.08 (0.18)	2,370 (5,230)
Acrolein	316 (696)	0.00	316 (696)
Arsenic	2.36 (5.20)	1.81 (3.99)	4.17 (9.19)
Asbestos	0.00	4.99 (11.0)	4.99 (11.0)
B[b]fluoranthen	0.00	0.00	0.00
B[e]pyrene	0.00	0.01 (0.02)	0.01 (0.02)
B[g,h,i]perylen	0.00	0.01 (0.02)	0.01 (0.02)
Benzene	1,680 (3,700)	625 (1,380)	2,300 (5,080)
CCl4	0.72 (1.6)	0.53 (1.2)	1.25 (2.76)
Cadmium	4.03 (8.88)	1.70 (3.75)	5.73 (12.6)
Chlorobenzn	0.81 (1.8)	0.00	0.81 (1.8)
Choroform	0.56 (1.2)	0.00	0.56 (1.2)
Chromium	18.6 (41.1)	0.00	18.6 (41.1)

Copper	7.33 (16.2)	0.00	7.33 (16.2)
Chrysene	0.00	0.01 (0.02)	0.01 (0.02)
Cr(VI)	0.14 (0.31)	0.11 (0.24)	0.25 (0.55)
DieselExhPM	74.9 (165)	0.00	74.9 (165)
DieselExhTOG	83.6 (184)	0.00	83.6 (184)
EDB	0.87 (1.9)	0.64 (1.4)	1.51 (3.3)
EDC	0.00	0.34 (0.75)	0.34 (0.75)
Ethyl Benzene	917 (2,020)	0.00	917 (2,020)
Fluoranthene	0.00	0.02 (0.04)	0.02 (0.04)
Fluorene	0.00	0.08 (0.18)	0.08 (0.18)
Fluorocarb(Cl)	0.00	90.7 (200)	90.7 (200)
Formaldehyde	21,900 (48,400)	2,930 (6,450)	24,900 (54,800)
H_2S	0.00	0.00	0.00
HCl	264 (582)	0.00	264 (582)
Hexane	10,200 (22,600)	0.00	10,200 (22,600)
Lead	13.4 (29.5)	9.39 (20.7)	22.8 (50.2)
Manganese	22.6 (49.9)	0.00	22.6 (49.9)
Mercury	2.87 (6.33)	0.00	2.87 (6.33)
Methanol	125 (276)	0.00	125 (276)
Methylene Chlor	1.68 (3.70)	0.29 (0.64)	1.97 (4.34)
NH_3	742 (1,640)	1,570 (3,460)	2,310 (5,100)
Naphthalene	65.0 (143)	24.4 (53.7)	89.4 (197)
Nickel	23. 8 (52.4)	4.41 (9.72)	28.2 (62.1)
PAHs	116 (256)	41.4 (91.2)	157 (347)
Perc	111 (244)	0.00	111 (244)
Phenanthrene	0.00	0.15 (0.33)	0.15 (0.33)
Propylene	1,490 (3,270)	0.00	1,490 (3,270)
Propylene Oxide	738 (1,630)	0.00	738 (1,630)
Pyrene	0.00	0.02 (0.04)	0.02 (0.04)
Selenium	3.13 (6.90)	0.00	3.13 (6.90)
Styrene	0.49 (1.1)	0.00	0.49 (1.1)
Toluene	31,300 (68,900)	0.00	31,300 (68,900)
Vinyl Chloride	0.00	0.22 (0.49)	0.22 (0.49)
Xylenes	2,710 (5,970)	0.00	2,710 (5,970)
Zinc	31.8 (70.2)	0.00	31.8 (70.2)

2.6.2.2. Greenhouse Gas Emission Estimates

GHG emissions for 2013 in terms of CO_2-equivalent mass (CO_2eq.) are reported for eight offshore facilities in the EPA's flight tool (U.S. EPA, 2015b). These facilities are platforms Hermosa, Hidalgo, Harvest, Gail, Edith, Ellen, Elly, and Eureka. Emissions from the Beta field (Edith, Ellen, Elly, and Eureka) were reported as a single emission value. Oil and gas production for Platform Gail (only platform in the Sockeye field) and for the Beta field are given in Tables 2.4-1 and 2.4-5, respectively. Oil and gas production data for platforms

Hermosa, Hidalgo, and Harvest were computed individually from BOEM production data (BOEM, 2015d). The production data were correlated with the CO_2eq. emissions as shown in Figure 2.6-1. Barrels of oil equivalent (BOE) were computed using a conversion factor of (5,620 cubic feet) of gas per BOE (BOEM, 2014a). A weighting factor of 6.3 on the gas BOE was found to produce the best correlation with CO_2eq.

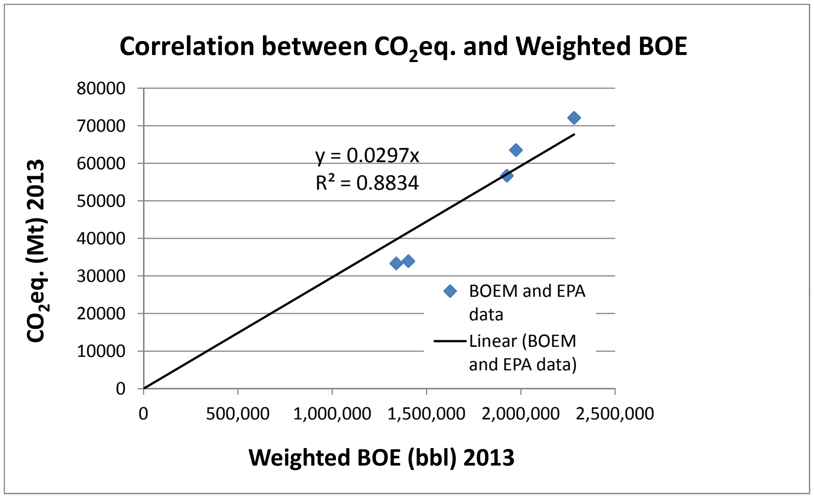


Figure 2.6-1. Correlation between oil production and CO_2eq. emissions.

Production data from Tables 2.4-1, 2.4-3, and 2.4-5 are used with the correlation to estimate GHG emissions. The values are shown in Table 2.6-8.

Table 2.6-8. Oil and gas production values for offshore regions in 2013 and GHG (CO_2eq.) emission estimates.

Region	**Oil (m^3) x10^6 (#bbl) x10^6**	**Gas (m^3) x10^6 (##Mcf) x 10^6**	**BOE* (m^3) x10^6 (bbl) x10^6**	**Weighted BOE (m^3) x10^6 (bbl) x10^6**	**CO_2eq. (metric tons) x10^6 (lbs) x10^6**
Santa Barbara Basin	2.53 (15.9)	696 (24.6)	3.23 (20.3)	6.91 (43.5)	1.29 (2,850)
Santa Maria Basin	0.511 (3.21)	98.9 (3.49)	0.511 (3.21)	1.13 (7.10)	0.212 (466)
Santa Barbara and Santa Maria Basins	3.04 (19.1)	795 (28.1)	3.74 (23.5)	8.04 (50.6)	1.50 (3,310)
Offshore Los Angeles Basin	2.17 13.6	131 (4.62)	2.30 (14.4)	2.99 (18.8)	0.558 (1,230)
Total	5.21 (32.8)	926 (32.7)	6.14 (38.6)	11.0 (69.5)	2.06 (4,550)

*#bbl = oil barrel (one barrel = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7,481 gallons); *BOE = barrels of oil equivalent*

As a check on the GHG emission estimate, GHG emissions from California oil production in 2012 can be estimated from total oil and gas production for California from DOGGR (2013) and BOEM (2012) using the correlation from Figure 2.6-1. This estimate may be compared with the CARB (2015b) GHG emission inventory report for California, which gives statewide emission estimates resulting from oil and gas production activity in 2012. The results are shown in Table 2.6-9.

Table 2.6-9. Oil and gas production values for California oil and gas production in 2012 and GHG (CO_2eq.) emission estimates.

Location	Oil (m^3) x10^6 (#bbl) x10^6	Gas (m^3) x10^6 (##Mcf) x10^6	BOE* (m^3) x10^6 (bbl) x10^6	Weighted BOE (m^3) x10^6 (bbl) x10^6	CO_2eq. (metric tons) x10^6 (lbs) x10^6
California	31.4 (198)	6,300 (222)	37.7 (237)	71.0 (447)	13.3 (29,300)
Federal offshore	2.81 (17.7)	771 (27.2)	3.58 (22.5)	7.66 (48.2)	1.43 (3,160)
Total	34.2 (215)	7,070 (250)	41.3 (260)	78.7 (495)	14.7 (32,400)

*#bbl = oil barrel (one barrel = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7,481 gallons); *BOE = barrels of oil equivalent*

The CARB estimate for 2012 GHG CO_2eq. emissions from oil and gas operations is 16,856,000 metric tons. It is not clear if the CARB estimate includes GHG emissions from federal offshore facilities, but if it does, the correlation-based emission estimate is about 13% smaller than the CARB estimate.

GHG emission estimates for California oil and gas production operations are also presented in Volume II, Chapter 3, Table 3.3-19. These estimates are based on a CARB industry survey conducted in 2007. The offshore CO_2eq. emissions estimates from the CARB survey are found to be much lower than the correlation-based estimates given here, which are based on CO_2eq. emissions estimates from the EPA flight tool. The reported 2013 offshore CO_2eq. emissions in the EPA flight tool totaled 260,000 metric tons but was only for 8 out of a total of 32 offshore facilities. The 2007 CARB industry survey reported 140,100 metric tons CO_2eq. emissions for all offshore operations. While the reasons behind the differences in emission estimates are not known, the higher estimates developed here are more consistent on a per unit hydrocarbon production basis with average California oil and gas production emission rates (see Section 2.7.2.3).

2.7. Impacts of Offshore Well Stimulation Activities and Data Gaps

The potential impacts of offshore well stimulation are related to the possibility of discharge of contaminants into the air and water, and the injection of stimulation fluids and produced water into the subsurface. This section explores the possibility that these may lead to contamination of the marine environment and atmosphere, and increased seismic activity.

2.7.1. Impacts of Offshore Well Stimulation to the Marine Environment

Data documenting the impacts of well stimulation fluids discharged to the marine environment have not been found. However, studies of ecological conditions and contamination in the marine environment around California offshore platforms have been conducted. Although these do not directly target the effects of well stimulation fluid discharge, the observations and findings from such investigations implicitly include the cumulative effects of all discharge that has occurred. In addition to these field investigations, laboratory investigations of toxicity of produced water discharge into the ocean have been conducted.

Ecological Studies around California Offshore Platforms

Several ecological studies have been conducted around California offshore platforms that provide information about the ecological effects of offshore platforms on marine life. Love et al. (2003) found that platforms support higher densities of many species of common reef fish at platforms compared to natural outcrops. Therefore, the platforms appear to act as a kind of marine refuge. A survey of fish counts for young-of-the-year (less than one year old) rockfishes, a dominant species at platforms and natural reefs in the Santa Barbara Channel area, shows in Figure 2.7-1 the higher density of species at Platform Hidalgo versus a natural outcrop about one kilometer from the platform, North Reef, over a six-year period. Differences in fish density were mainly due to differences in the abundance of various rockfish species, rather than differences in the kinds of species present.

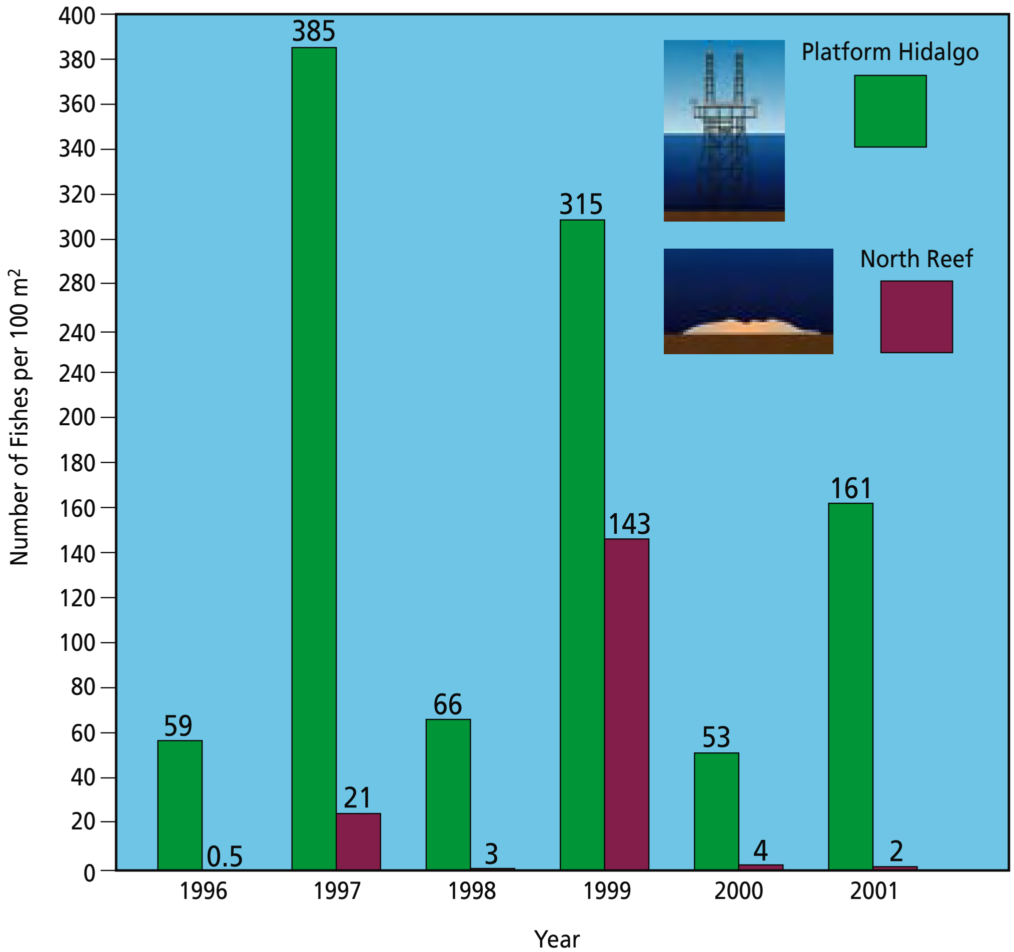


Figure 2.7-1. Young-of-the-Year Rockfish densities at Platform Hidalgo and North Reef (Love et al., 2003).

A comparison of the growth rates for young-of-the year blue rockfish at Platform Gilda and at Naples Reef is shown in Figure 2.7-2. Note that platform Gilda was found to have the most hydraulic fracturing treatments of any platform in federal waters (see Table 2.5-2). Growth rates measured using the otoliths (earbones) of the fish were found to be 0.046 cm/day (0.018 inches/day) and 0.014 cm/day (0.0055 inches/day) for Platform Gilda and Napes Reef, respectively, based on the straight-line fits in Figure 2.7-2. The difference in growth rates was found to be statistically significant (Love et al., 2003).

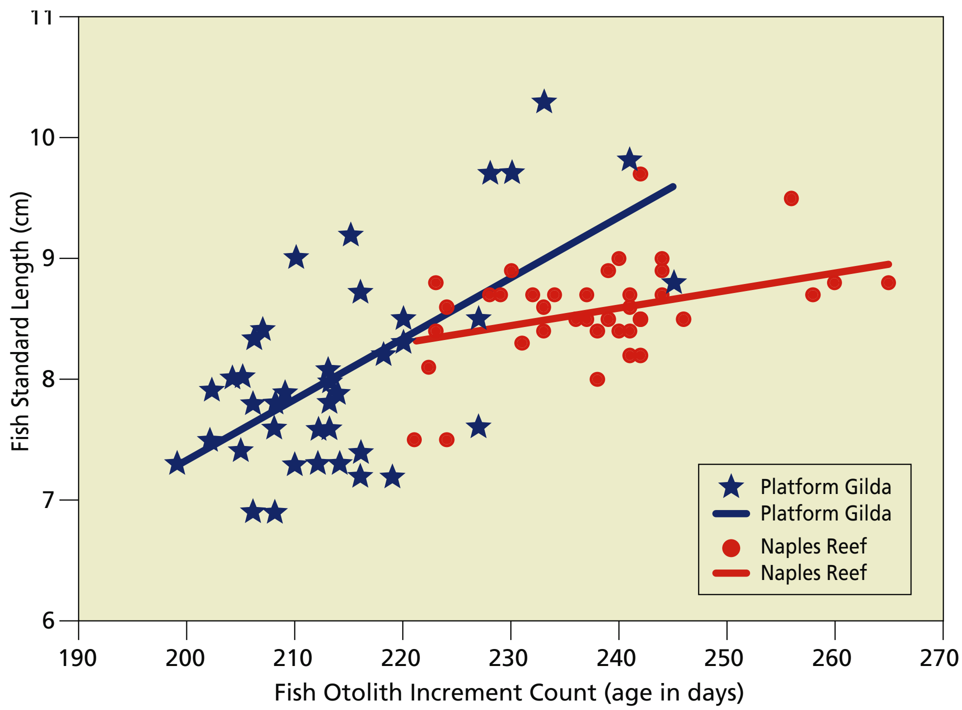


Figure 2.7-2. Growth rate comparison for Platform Gilda and Naples Reef in 1999 (Love et al., 2003).

Fish production rates have been found to be about an order of magnitude higher at California offshore platforms compared with other natural areas studied around the world (Claisse et al., 2014). Locations where production rates have been quantified are shown in Figure 2.7-3. Figure 2.7-4 presents the total production rates of fish mass per unit area at 16 platforms and 7 natural areas. This shows that higher production rates are found around platforms than in natural areas. In Figure 2.7-4, total production is divided between somatic (yellow portion of total growth bars) and recruitment production (purple portion of total growth bars). Somatic production is the increase of mass in the existing fish population, whereas recruitment production is the growth of fish mass through reproduction. Similar findings of high densities of cowcod and bocaccio around Platforms Gail and Hidalgo were reported by Love et al. (2005).

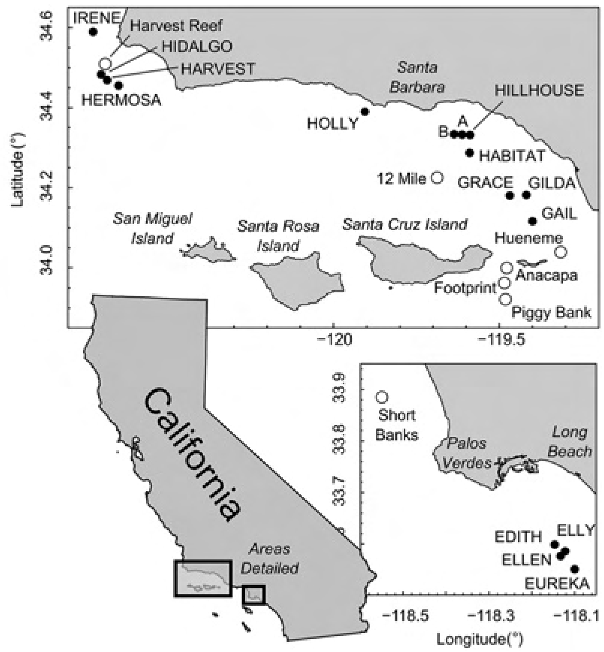


Figure 2.7-3. Locations where fish production rates have been quantified (Claisse et al., 2014). Solid circles are platforms and open circles are natural areas.

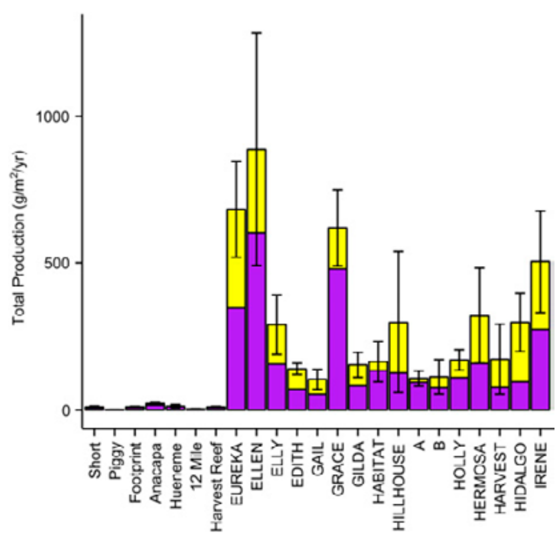


Figure 2.7-4. Fish mass production rates at platforms (with names all in upper case letters) with natural areas (denoted by names using both upper and lower case letters). (Claisse et al., 2014). The yellow and purple indicate the split in production between somatic production (the growth of individuals) and recruitment production (an increase in the number of individuals).

The underlying reason for the improved environment for marine life around platforms is thought to be a result of (1) platforms having a high ratio of habitat surface area to seafloor area and (2) platforms providing protection because access is restricted around the platform, and (3) platforms tend to be in isolated locations (Martin and Lowe, 2010; Claisse et al., 2014). Although these factors do not address the impacts of fluids discharged on the marine environment, the findings of robust fish populations around platforms imply that any adverse impacts of intentional fluid discharge are less than the other advantages afforded by the platform environment.

Osenberg et al. (1992) conducted a study of benthic marine organism densities and growth rates at a location near Carpinteria, about 200 to 300 m (656 to 985 feet) offshore in 10 to 12 m (33 to 39 feet) of water. Osenberg et al. (1992) state that produced water was discharged at this location nearly continuously at a rate of 2,640 m^3/day (16,600 bbl/day). Densities of the benthic organisms were found to be quite sensitive to distance from the diffuser within a range of approximately 100 m. One group of organisms, nematodes (roundworms), were found to benefit from exposure to the produced water, while a second group, polychaetes (segmented worms), displayed a reduction in density within 100 m (328 ft) of the produced water discharge (Figure 2.7-5). Other organisms, including mussels, showed no distinct variation in density with distance from the outfall. However, mussel growth rates were found to be more sensitive, with depressed rates found as a function of distance up to one kilometer away from the discharge point (Figure 2.7-6). However, observations of mussel growth rates at offshore platforms have been found to be higher than for corresponding natural habitats (Claisse et al., 2014). One possibility is that the effects of discharge may have been amplified in this relatively shallow environment compared with offshore platforms in the Santa Barbara Channel area, where water depths are 29 m (95 ft) or more (see Tables 2.5-1 and 2.5-4), as suggested by Gale et al. (2012). Baake et al. (2003) investigated similar impacts caused by oil production operations in the North Sea and found that the effects of produced water discharge result in sublethal effects for some species up to one to two kilometers from the discharge point.

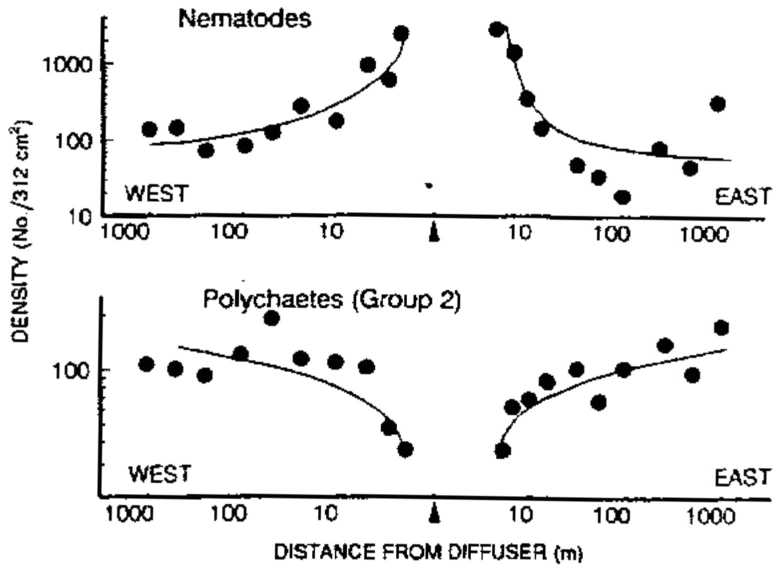


Figure 2.7-5. Densities of benthic organisms as a function of distance from the Carpinteria produced water outfall (Osenberg et al., 1992).

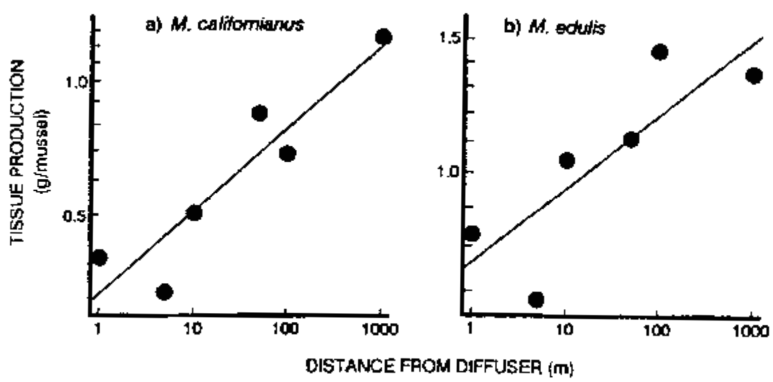


Figure 2.7-6. Variations in mussel tissue growth rates with distance from the Carpinteria outfall for two species, a) M. californianus; and b) M. edulis (Osenberg et al., 1992).

A study of pollutant-related reproductive impairment in fish called atresia was conducted by Love and Goldberg (2009) on the Pacific sanddab. Discharge of drilling muds and produced water were identified as sources of contamination at the platform sites. The study was performed at two offshore platforms, Gilda and B, and two natural areas, Rincon and Santa Cruz, for comparison. The locations of the sites are shown in Figure 2.7-7.

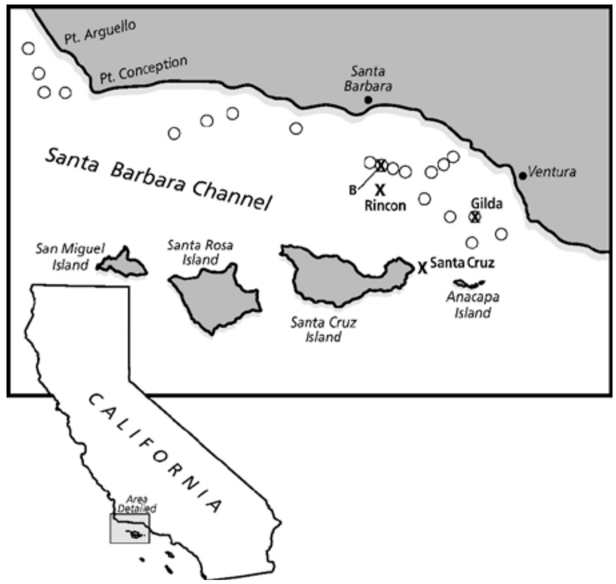


Figure 2.7-7. Locations for samples to investigate atresia in the Pacific sanddab (Love and Goldberg, 2009).

The study was conducted to compare the reproductive capability of the Pacific sanddab at oil platforms and natural areas. The following observations were used to evaluate reproductive health: (1) hydrated eggs for upcoming spawning; (2) vitellogenesis (yolk deposition) in mode of smaller eggs for subsequent spawning; (3) postovulatory follicles (evidence of recent spawning); (4) follicular atresia (degenerating oocytes (egg cell)), characterized as minor or pronounced. Results are shown in Table 2.7-1, where higher percentages of hydrated eggs, yolks in smaller modes, and post-ovulatory follicles correspond to positive reproductive characteristics, whereas occurrences of atresia, particularly pronounced atresia, correspond to reproductive impairment. Love and Goldberg (2009) concluded that the data do not show substantial reproductive impairment in fish living at the platforms, and that large-scale reproductive damage is unlikely to be occurring.

Table 2.7-1. Pacific sanddab reproductive characteristics at two platform and two natural sites (Love and Goldberg, 2009).

Site	n	Hydrated eggs	Yolks in smaller modes	Post-ovulatory follicles	Minor atresia	Pronounced atresia
Platform B	18	95	95	61	22	6
Rincon	19	50	55	5	35	16
Platform Gilda	20	100	100	35	60	0
Santa Cruz	21	85	85	65	15	0

Values in each column are in percentages of individuals sampled.

2.7.1.2. Contamination Studies around California Offshore Platforms

Studies of certain types of contamination around California offshore platforms have also been conducted. These studies include polycyclic aromatic hydrocarbons (PAH) that are a component of crude oil as well as other organic contaminants unrelated to petroleum operations (Gale et al., 2012; 2013; Bascom et al., 1976), trace metals contained in drilling muds and produced waters (Love at al., 2013; Bascom et al., 1976), and reproductive impairment in marine life (atresia) caused by exposure to environmental contamination (Love and Goldberg, 2009).

Gale et al. (2012, 2013) investigated the levels of PAH in Pacific sanddabs, kelp rockfish, and kelp bass. Pacific sanddabs are benthic-dwelling flatfish that are ubiquitous in the southern California marine environment and found both at natural sites and around oil and gas platforms. Kelp rockfish and bass are found at mid-water depths around platforms and at rocky reef natural sites. The locations investigated are shown in Figure 2.7-8, which include 7 platforms and 12 natural sites.

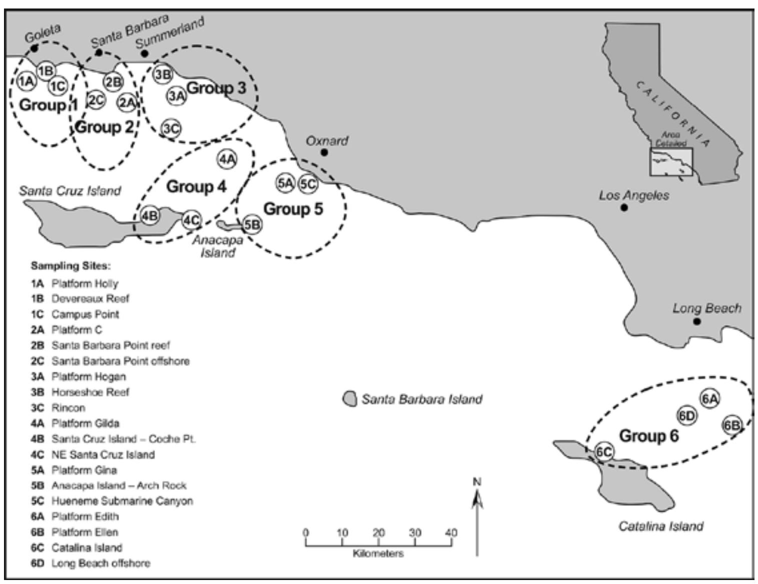


Figure 2.7-8. Sites investigated for PAH contamination (Love et al., 2013).

The investigation involved sampling bile from the fish gall bladders and measuring contamination levels. Because PAHs are rapidly metabolized in the fish livers, PAH metabolites in the bile were the target chemical species in the investigation. This methodology has been used to successfully identify PAH contamination in fish exposed to natural oil seeps relative to other areas that have not been exposed to petroleum seepage (Gale et al., 2013). The study used 74 fish samples from the platform sites and 64 fish samples from the natural sites. The results of the study found that PAH exposure in resident fish populations at platforms is not observably different than in fish from nearby natural areas. 1-Hydroxypyrene, which has been used as a bioindicator of PAH exposure of fish, was not detected in any samples from the platform sites, and only low levels of 1-hydroxypyrene were detected in 3 of 12 kelp rockfish from the Santa Barbara Point reef. The highest levels of PAH metabolites were found in fish near Platform Holly, although even these levels of contamination were considered low by Gale et al. (2012). Platform Holly is in state waters and does not discharge wastewater to the ocean. Detectable PAH metabolite concentrations at platforms in federal waters (at platforms Gilda, Gina, and Hogan) were at levels comparable to detectable concentrations at natural sites.

Gale et al. (2013) performed a follow-on study to Gale et al. (2012), which again considered PAH contamination but also included aliphatic hydrocarbons found in crude oil and several other organic contaminants (polychlorinated biphenyls, organochlorine pesticides, and polybrominated diphenylethers) not related to oil and gas production. The PAH study involved measurements of recalcitrant, higher molecular weight PAHs in fish tissues of Pacific sanddab. These allow for detection of potential chronic exposure to PAHs not readily detectable by PAH metabolite measurements in the earlier study. The same sampling sites as shown in Figure 2.7-8 were used for the follow-on study. The results of the study found that aliphatic hydrocarbon concentrations were uniformly low, less than 100 ng/g per component, in all samples from the platforms and the natural locations. Total-PAH concentrations were found to range from 15 to 37 ng/g at natural areas and from 8.7 to 22 ng/g at platforms. The types of PAHs found at all natural and platform sites were similar. Balk et al. (2011) found a somewhat different result investigating levels of four PAH metabolites in fish bile at two oil production sites in the North Sea. There were three out four metabolites at one of the sites that showed statistically significant higher concentrations than the control. None of the metabolites was significantly different than the control at the other site.

A study of trace metals in fish around California platforms was conducted by Love et al. (2013) during 2005-2006. The study was conducted at 5 of the 7 platform sites (excludes platforms C and Ellen) and 10 of the 12 natural areas (excludes Santa Barbara Point reef and Santa Barbara Point offshore) shown in Figure 2.7-8. This study evaluated results for 21 trace metals in 98 Pacific sanddabs, 80 kelp rockfish, and 18 kelp bass. These species were selected because they are common at both natural and platform sites, and because they are likely to ingest prey containing elevated concentrations of trace elements.
In particular, the benthic-dwelling sanddab, which ingests benthic infauna, might be expected to accumulate trace metals. The elements evaluated are aluminum, arsenic, barium, cadmium, chromium, cobalt, copper, gallium, iron, lead, lithium, manganese, mercury, nickel, rubidium, selenium, strontium, tin, titanium, vanadium, and zinc. These trace metals are present in drilling muds, produced water, and crude, such that they may end up in waste discharge streams from some platforms in federal waters. The trace metal measurements were conducted on whole-fish samples. Of the 21 elements, concentrations of 6 trace metals were found to exceed toxicity thresholds. These six elements of concern are listed in Table 2.7-2, along with the number of fish that exceeded the toxicity

threshold at platforms and natural areas. For example, 4 out of 10 kelp bass sampled in natural areas were found to have exceeded the toxicity threshold for arsenic, and 17 out of 48 Pacific sanddabs sampled at platforms were found to exceed the toxicity threshold for cadmium. As can be seen from Table 2.7-2, the results do not indicate that trace metal contamination at oil platforms is significantly different than in natural areas.

Table 2.7-2. Numbers of fish contaminated (with percent of total sampled in parentheses) beyond toxicity threshold (Love et al., 2013).

	Kelp Bass		**Kelp Rockfish**		**Pacific Sanddabs**	
Trace Metals	Platforms	Natural Areas	Platforms	Natural Areas	Platforms	Natural Areas
arsenic	0	4 (40%)	0	14 (35%)	7 (15%)	6 (12%)
cadmium	1 (13%)	0	2 (5%)	0	17 (35%)	22 (44%)
chromium	0	0	0	0	0	22 (44%)
lead	0	0	1 (3%)	0	0	0
mercury	3 (38%)	9 (90%)	1 (3%)	10 (25%)	7 (15%)	3 (6%)
selenium	0	0	0	0	0	2 (4%)
Number of fish sampled	8	10	40	40	48	50

2.7.1.3. Laboratory Investigations of the Impact of Waste Discharge from Offshore Oil and Gas Operations on the Marine Environment

Other investigations concerning produced water impacts on the marine ecological environment have been conducted. A laboratory toxicological study by Raimondi and Boxshell (2002) concerned the effects of produced water on the California offshore environment. In this study, the reproductive behavior of a selection of marine invertebrates was examined after exposure to various levels of diluted produced water mixed with seawater. In particular, results for the species Watersipora subtorquata, are highlighted here. A colonial marine species, W. subtorquata, spends its adult life attached to hard substrates, including rocks, shells, docks, vessel hulls, etc. Larvae are formed within the adult colony prior to release to the water column for a brief free-swimming stage lasting a few hours, after which the larvae settle out and attach to a hard surface to continue further stages of development. Laboratory experiments were conducted in which W. subtorquata larvae were exposed to different concentrations of produced water from an offshore oil and gas operation mixed with seawater. The experiments then tracked swimming time and attachment rates to assess any sublethal effects on the larval development stage. After 90 minutes, larvae not exposed to produced water were found to still be swimming, whereas none of the larvae at 10% produced water concentration were mobile after 15 minutes. Figure 2.7-9 shows the effects of exposure time and concentration on the percentage of larvae still swimming after 15 and 75 minutes. Despite the distinct sublethal effects observed, no evidence was found that these impacts in the larval stage carried over and impacted the growth or competitive abilities of the subsequent W. subtorquata adults. Similar results were found for other invertebrate species investigated.

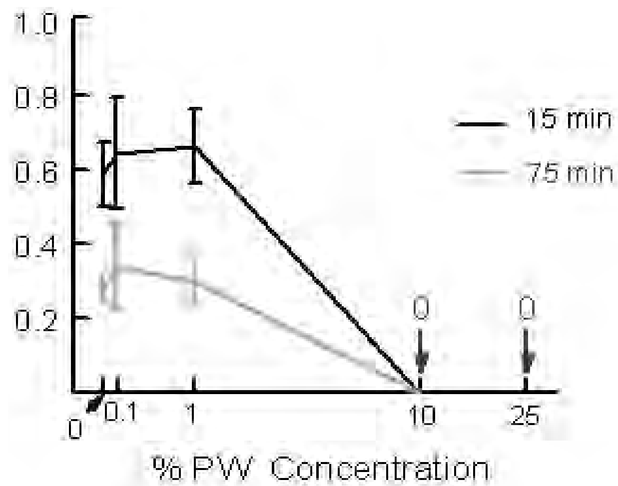


Figure 2.7-9. Impacts of produced water concentration on the fraction of W. subtorquata larvae still swimming after 15 and 75 minutes (Raimondi and Boxshell, 2002).

A study conducted by Krause et al. (1992) was performed using the same produced water investigated by Osenberg et al. (1992) (see Section 2.7.1.1). This study investigated the effects of produced water on reproductive behavior of the purple sea urchin. The reproductive behavior of the purple sea urchin is representative of other benthic marine organisms that broadcast eggs and sperm into the water where fertilization takes place. Treatments were performed using either specific dilutions of the raw produced water with seawater or samples taken from the ocean at various distances from the outfall. Although concentrations of up to 1% produced water had no effect on mortality, both specific dilutions and field samples produced sublethal effects that depressed the rate of reproductive development at dilutions as high as 1,000,000:1. The percentage of embryos reaching the pluteus (larval) stage as a function of exposure type and produced water dilution is shown in (Figure 2.7-10).

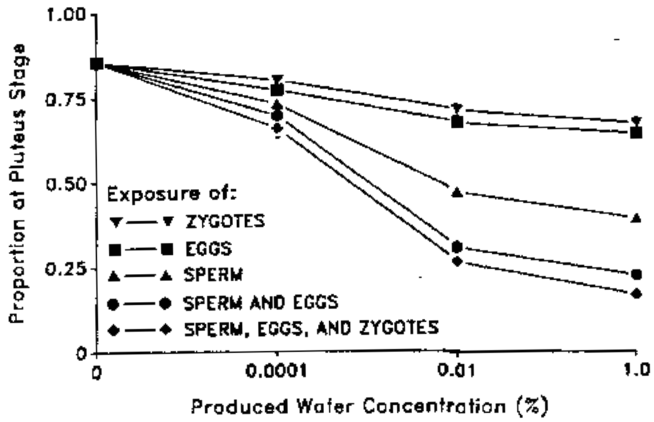


Figure 2.7-10. Effects of produced water concentration on various exposure scenarios for the development of embryos to the pluteus (larval) stage after 48 hours (Krause et al., 1992).

The depressed development, however, was shown to be temporary, in that after 96 hours the progression to the pluteus stage was independent of the level of produced water exposure (Figure 2.7-11), with the control and different exposure scenarios converging to a value of about 85% at 96 hours. While such sublethal effects may lead to increased mortality or an overall reduction in reproductive success in the natural environment, insufficient information exists to extrapolate these results to ecological consequences in the field.

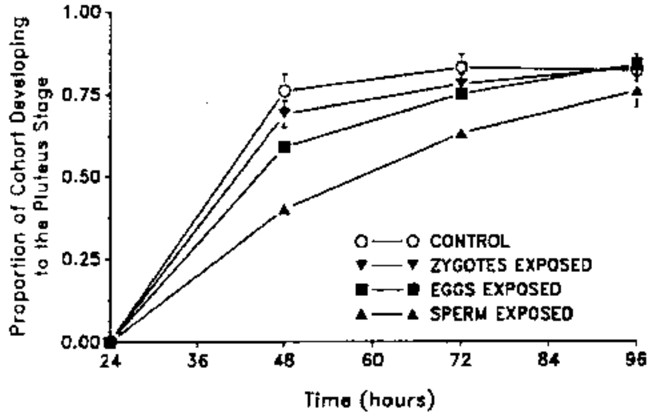


Figure 2.7-11. The effects of 1% produced water exposure scenarios on development to the pluteus stage as a function of time (Krause et al., 1992).

2.7.1.4. Evaluation of Typical Well Stimulation Chemicals and Marine Ecotoxicity

Marine ecotoxicity analyses were conducted on two stimulation fluid compositions as an alternative approach to evaluate the impacts of ocean discharge of stimulation fluid flowback. Because flowback compositions were not available, the discharge was assumed to consist of the same composition as the stimulation fluids. The hydraulic fracturing fluid composition was taken from a DOGGR public disclosure report (DOGGR, 2014c). Fracturing fluid compositions were only available for onshore treatments, and all but two of those reported were for diatomite. The two others were for Pico/Repetto sandstone, which is a more likely type of lithology offshore than diatomite. The fracturing fluid with the highest chemical load was selected, which is shown in Table 2.7-3. Acidizing stimulation fluid compositions were taken from another DOGGR public disclosure report (DOGGR, 2014d). As for fracturing fluid, the only compositions available were from onshore stimulations. The acidizing treatment selected for analysis utilized three distinct fluids that are commonly used sequentially for acidizing. The three fluids are (1) an HCl acid preflush fluid, (2) a main acidizing fluid that was generated from mixing hydrochloric acid and ammonium bifluoride to produce an HCl/HF mud acid, and (3) an ammonium chloride overflush fluid. The compositions are given in Table 2.7-4. For these acidizing fluids, some of the additives could not be analyzed because the concentrations used were not provided in the disclosure, even though the chemicals were listed as part of the fluid.

The maximum percentage by mass was converted to a diluted concentration by assuming a fluid density of 1 kg/liter and an average dilution factor of 746. The average dilution factor is based on a harmonic average of the minimum and maximum dilutions given in Section 2.6.1.1. A coarse toxicity screen was conducted by utilizing all available data in the ECOTOX database (U.S. EPA, 2015c). The predicted average concentration of each chemical following dilution was compared to the lowest available acute or chronic LC50 or EC50 toxicity value for 90 marine species in the following six species groups: algae, moss, fungi; crustaceans; fish; invertebrates; molluscs; and worms. The hydraulic fracturing case study included 33 chemicals. Seven (21%) of these chemicals had toxicity data for marine organisms, and 26 (79%) did not. Out of the seven chemicals with toxicity data, none was predicted to occur at concentrations above acute or chronic toxicity levels. The acidifying case study included 17 distinct chemicals (note that several of the chemicals in Table 2.7-4 are used in more than one of the three acidizing stages). Twelve (71%) had toxicity data in marine organisms, and 5 (29%) did not. Out of the 12 chemicals with toxicity data, two were predicted to occur at concentrations above acute or chronic toxicity levels: ammonium chloride and dodecylbenzenesulfonic acid.

The biocide 5-Chloro-2-methyl-3(2H)-isothiazolone (CMIT) was associated with some of the lowest acute or chronic toxicity values for marine species out of the chemicals screened for this case study. However, the volume of CMIT used in the offshore case study resulted in very low predicted concentrations in surrounding waters. Further study of the use of CMIT and its potential toxicity to marine species is needed.

The lack of toxicity data for 31 of the 48 distinct chemicals (methanol and ethylene glycol are in both hydraulic fracturing and acidizing fluids and both have toxicity data) is a significant problem with this evaluation approach. An additional important caveat is that the approach used here cannot address toxic interactions between chemicals in a complex mixture such as these stimulation fluids. Similarly, very little data were available on chronic impacts of these chemicals in the marine environment. These represent critical data gaps in the analysis of potential impacts of offshore drilling to sensitive marine species.

Table 2.7-3. Hydraulic fracturing fluid composition (DOGGR, 2014c)

Chemical Constituent	CAS	Maximum percentage by mass
Crystalline Silica: Quartz (SiO_2)	14808-60-7	29.08368%
Guar Gum	9000-30-0	0.25305%
Paraffinic Petroleum Distillate	64742-55-8	0.12652%
Petroleum Distillates	64742-47-8	0.12652%
Oxyalkylated Amine Quat	138879-94-4	0.04739%
Methanol*	67-56-1	0.03048%
Diatomaceous Earth, Calcined	91053-39-3	0.02959%
Sodium Chloride*	7647-14-5	0.02564%
1-Butoxy-2-Propanol	5131-66-8	0.02109%
Isotridecanol, Ethoxylated	9043-30-5	0.02109%
Cocamidopropylamide Oxide	68155-09-9	0.01588%
Cocamidopropyl Betaine	61789-40-0	0.01588%
Boric Acid (H_3BO_3)*	10043-35-3	0.01524%
Methyl Borate	121-43-7	0.01524%
Ammonium Persulfate*	7727-54-0	0.00667%
Nitrilotris (Methylene Phosphonic Acid)	6419-19-8	0.00444%
Quaternary Ammonium Chloride	61789-71-7	0.00444%
Hemicellulase Enzyme Concentrate	9025-56-3	0.00379%
Potassium Bicarbonate	298-14-6	0.00311%
Glycerol	56-81-5	0.00159%
Caprylamidopropyl betaine	73772-46-0	0.00159%
Acid Phosphate Ester	9046-01-9	0.00148%
Vinylidene Chloride-methylacrylate polymer	25038-72-6	0.00062%
5-Chloro-2-Methyl-4-Isothiazolin-3-One*	26172-55-4	0.00049%
Magnesium Nitrate	10377-60-3	0.00049%
2-Butoxy-1-Propanol	15821-83-7	0.00042%
2-Methyl-4-Isothiazolin-3-One	2682-20-4	0.00024%
Magnesium Chloride*	7786-30-3	0.00024%
Phosphonic Acid	13598-36-2	0.00015%
Ethylene Glycol*	107-21-1	0.00015%
Crystalline Silica: Cristobalite	14464-46-1	0.00005%
Hydrated magnesium silicate	14807-96-6	0.00002%
Poly(tetrafluoroethylene)	9002-84-0	0.00001%

Note: Stimulation fluid for well API 411122247, Ventura Oil Field

** Chemical with toxicity data.*

Table 2.7-4. Matrix acidizing fluid composition

Stages	Chemical Constituent	CAS	Maximum percentage by mass
HCl preflush	Acetic acid*	64-19-7	0.9828%
	Citric acid*	77-92-9	0.8288%
	Hydrochloric acid*	7647-01-0	15.3241%
	Methanol*	67-56-1	0.0795%
	Diethylene glycol*	111-46-6	0.3136%
	Cinnamaldehyde	104-55-2	0.3136%
	Formic acid*	64-18-6	0.8317%
	Isopropanol*	67-63-0	0.1233%
	Dodecylbenzene sulfonic acid*†	27176-87-0	0.4780%
	2-butoxyethanol*	111-76-2	1. 9997%
	Ethoxylated hexanol	68439-45-2	0.1514%
	Ethylene glycol*	107-21-1	0.0022%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0088%
main acid (HCl/HF)	Hydrochloric acid*	7647-01-0	14.7779%
	Ammonium bifluoride	1341-49-7	4.3887%
	Methanol*	67-56-1	0.0795%
	Diethylene glycol*	111-46-6	0.3136%
	Cinnamaldehyde	104-55-2	0.3136%
	Formic acid*	64-18-6	0.8317%
	Isopropanol*	67-63-0	0. 1215%
	Citric acid*	77-92-9	0.0395%
	Hydroxylamine hydrochloride	1304-22-2	0.0395%
	Silica, amorphous - fumed	7631-86-9	0.0003%
	Dodecylbenzene sulfonic acid*†	27176-87-0	0.4707%
	2-butoxyethanol*	111-76-2	1.9687%
	Ethoxylated hexanol	68439-45-2	0.1491%
	Ethylene glycol*	107-21-1	0.0022%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0087%
overflush	Isopropanol	67-63-0	0.0854%
	Ammonium chloride*†	12125-02-9	5.0009%
	2-butoxyethanol*	111-76-2	0.1685%
	Ethylene glycol*	107-21-1	0.0012%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0047%

Note: Stimulation fluid for well API 403052539, Elk Hills Oil Field.

** Chemical with toxicity data.*

†These chemicals exceeded the toxicity limits for some species.

2.7.1.5. Discussion of Impacts of Well Stimulation Fluids Discharge to the Marine Environment

Direct evidence for impacts of well stimulation fluid discharge into the marine environment is not available. The available information only provides a rough idea concerning the magnitude of stimulation activity conducted offshore, and the composition and disposition of stimulation flowback fluids are not known. There are no studies of stimulation or flowback fluids effects on the marine environment. Our analysis of stimulation fluids indicated that some constituents of matrix acidizing fluids could be discharged at levels that are acutely toxic to marine organisms; this seems less likely for hydraulic fracturing fluid constituents. However, our analysis was based on a number of reasonable assumptions; empirical data on the constituents of discharges from offshore platforms following stimulation is lacking. Wastewater discharge conducted by facilities in federal waters, including produced water, drilling muds, and well stimulation fluids, contain a number of toxic contaminants, including hydrocarbons, heavy metals, and chemical additives such as corrosion inhibitors and biocides (Volume II, Chapter 2). The effects of produced water have been shown to have some sublethal impacts on reproductive behavior and possibly on the overall health of some species. However, studies of the fish populations and contamination levels in fish around California offshore facilities appear to indicate that adverse affects are offset by the increased habitat afforded by the offshore oil and gas facilities. Contamination studies suggest that contaminant exposure levels, presumably as a result of the level of dilution of contaminants discharged, have remained below levels that result in significant adverse impacts. While some level of adverse impacts are likely as a result of wastewater discharge in general, these appear to be subtle relative to positive effects of habitat associated with offshore oil and gas facilities.

2.7.2. Impacts of Offshore Well Stimulation to Air Emissions

The main impacts of offshore air emissions of criteria and toxic pollutants are on air quality locally, while GHG emissions impact climate globally.

2.7.2.1. Criteria Pollutants

Offshore air emissions of criteria pollutants contribute to air pollution within geographical domains identified by CARB as “air basins.” These basins are shown in Figure 2.7-12. Offshore oil and gas production facilities in the Santa Maria and Santa Barbara Basins are closest to the South Central Coast Air Basin. This air basin consists of San Luis Obispo, Santa Barbara, and Ventura counties. Offshore oil and gas production facilities in the offshore Los Angeles Basin are closest to the South Coast Air Basin. This air basin consists of parts of Los Angeles, San Bernardino and Riverside counties, and all of Orange County. Pollutants released within an air basin move freely within the basin and are generally retained within the basin, but may sometimes be transported from one basin to another.

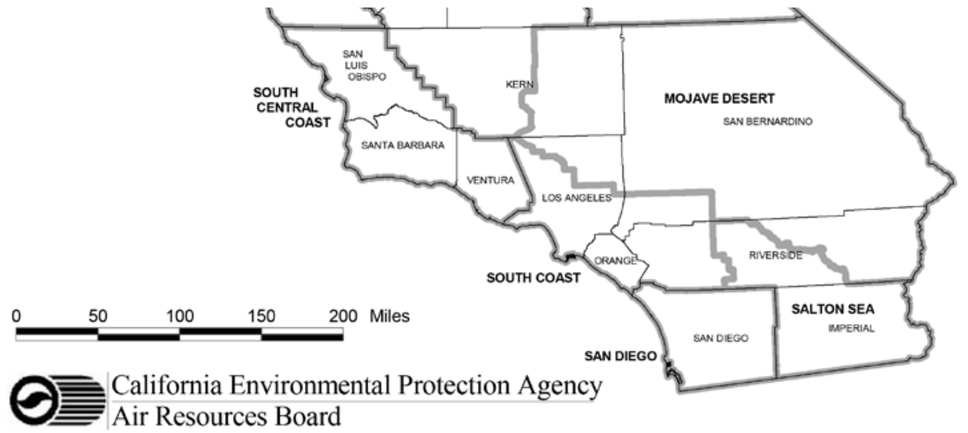


Figure 2.7-12. Southern California air basins and counties.

Offshore emissions reported in Table 2.6-6 are compared in Table 2.7-5 with emissions within the respective air basins.

Table 2.7-5. Offshore oil and gas production criteria pollutant emissions for 2012 compared with overall air basin emissions,(metric tons (lbs)) a) South Central Coast Air Basin; b) South Coast Air Basin. (CARB, 2015a).

a)

Emission Location	TOG	ROG	CO	NOx	SOx	PM	PM10	PM2.5
South Central Coast Air Basin	60,600 (1.34×10^8)	25,600 (5.63×10^7)	109,000 (2.40×10^8)	23,400 (5.15×10^7)	729 (1.61×10^6)	25,300 (5.57×10^7)	14,400 (3.16×10^7)	4,310 (9.51×10^6)
Offshore Oil and Gas Production	912 (2.01×10^6)	471 (1.04×10^6)	346 (7.63×10^5)	368 (8.11×10^5)	100 (2.21×10^5)	51.7 (1.14×10^5)	50.9 (1.12×10^5)	49.0 (1.08×10^5)
Percentage	1.5%	1.8%	0.3%	1.6%	13.8%	0.2%	0.4%	1.1%

b)

Emission Location	TOG	ROG	CO	NOx	SOx	PM	PM10	PM2.5
South Coast Air Basin	503,000 (1.11×10^9)	209,000 (4.61×10^8)	853,000 (1.88×10^9)	171,000 (3.77×10^8)	6,630 (1.46×10^7)	82,200 (1.81×10^8)	60,900 (1.34×10^8)	31,100 (6.87×10^7)
Offshore Oil and Gas Production	113 (2.50×10^5)	58.0 (1.28×10^5)	29.3 (6.46×10^4)	219 (4.84×10^5)	0.1 (220)	6.9 (1.52×10^4)	6.7 (1.48×10^4)	6.7 (1.48×10^4)
Percentage	0.023%	0.028%	0.003%	0.128%	0.002%	0.008%	0.011%	0.021%

Criteria pollutants emitted by offshore oil and gas production facilities have been found to be less than 2% of the total emissions in the South Central Coast Air Basin (San Luis Obispo, Santa Barbara, and Ventura counties) except for SOx, where offshore emissions account for 13.8% of the overall air basin emissions. For offshore Los Angeles, the air emissions from offshore oil and gas production facilities are an even smaller fraction of the total criteria pollutant emissions compared with emissions within the South Coast Air Basin. Well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total criteria pollutants emitted by offshore oil and gas production. Therefore, the impacts to the total air emissions are believed to be small.

2.7.2.2. Toxic Pollutants

Toxic air pollutants are also emitted by offshore oil and gas production facilities. The role of well stimulation in the emission of these toxic pollutants cannot be ascertained, because the fraction of emissions due to well stimulation has not been documented. However, several of the toxic pollutants emitted are also components of well stimulation fluids, including methanol, hydrochloric acid, xylene, ethyl benzene, toluene, and naphthalene. Given that offshore oil and gas production facilities have a buffer zone between the location of the emissions and the public, the public health effects may be expected to be reduced as a result of attenuation of impacts with distance. The impacts of toxic pollutant emissions on public health in Volume II, Chapter 6, indicate that the distance at which effects become negligible is about 3 km. Distances of the offshore facilities to land given in Tables 2.5-1 and 2.5-4 suggests that toxic air emissions from the facilities in federal waters should have negligible public health effects, but facilities in state waters (and onshore facilities that access offshore reservoirs) may have some impact, depending on population distributions in the near-shore areas around these facilities. However, these impacts are likely to be small compared with the emissions from onshore oil and gas production activities in the same air basins. Therefore, the impacts of toxic air emissions are expected to be low with respect to public safety, but may be of more concern for worker safety. Of the 12 facilities within 3 km of the coastline, nine are near Los Angeles and Orange Counties. A more detailed analysis of the proximity effects of air emissions in a populated urban setting is given in Chapter 4 of this volume for the Los Angeles case study.

2.7.2.3. Greenhouse Gases

The impact of GHG emissions is on global climate behavior rather than local air quality. Therefore, a comparison to air basin GHG emissions is not useful. Instead, the comparison is made to California GHG emissions for oil production activities per unit BOE output. This is a comparison indicating the level of GHG emissions relative to the value of the activity. Higher GHG emissions per unit BOE output indicate greater cost of production in terms of global climate impact. A more complete analysis would consider the total life-cycle GHG emissions per BOE, including refining, transportation, and combustion downstream of oil production activities, but this lies outside the domain of this study. From Table 2.6-9, the level of GHG emissions for California oil production activities (including offshore) per unit

BOE production can be computed to be 0.057 Mt CO_2eq./BOE, while offshore production alone is found to have a value of 0.053 Mt CO_2eq./BOE. Therefore, offshore oil production is estimated to have a 6% lower GHG emission rate per BOE production than for overall California oil production activities. For comparison, using the 2012 CARB CO_2eq. emission estimate of 16.9 million tons for all California oil and gas production, the emission rate lies between 0.065 and 0.071 metric tons CO_2eq./BOE, depending on whether or not the CARB estimate includes federal offshore emissions. Given the uncertainties in these estimates, the GHG emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations.

2.7.3. Impacts of Offshore Well Stimulation on Induced Seismicity

As described in Volume II, well stimulation itself does not result in sufficient quantities of fluid injected into the subsurface to be a significant hazard in terms of induced seismicity. Produced water disposal, which involves much greater volumes of water, has a greater potential to facilitate seismic activity if this water adds to the total volume of fluid in the local underground environment. Injection of produced water back into the formation from which it was withdrawn does not involve a net increase in fluid volume within the injection horizon. Therefore, this type of injection process is not expected to have much influence on seismic activity.

Most of the wastewater generated at offshore oil and gas production facilities in federal waters is discharged to the ocean. Three platforms in federal waters (Irene, Gail, Ellen) inject most of their produced water (> 94%). The 20 other platforms in federal waters inject only a small fraction of their produced water (< 15%), and the remainder is discharged into the ocean (CCC, 2013). The volume of produced water injected in federal waters has not been quantified, nor has whether or not this injection is into producing reservoirs or some other horizon used for disposal.

The state offshore oil and gas production operations produced 7.2×10^7 m^3 (4.5×10^8 bbl) of water in 2013. There are only 11 active, idle, or new water disposal wells in state waters. These wells dispose of only about 1.3% of all produced water generated by offshore facilities in state waters. Most of the remaining produced water is injected into the producing oil reservoirs.

The water disposal volumes cannot be quantified in all cases for operations in federal waters. However, using the maximum of 15% injection for platforms other than Irene, Gail, and Ellen, a maximum volume can be estimated. This is a maximum disposal volume because some platforms inject less than 15% of the produced water, and some of this injection is not disposal but injection back into the producing oil reservoir. The estimated maximum water disposal volume offshore in the Santa Barbara and Santa Maria basins is about 9.1 million m^3 (57 million barrels) in 2013, including facilities in federal and state waters. Although difficult to quantify, only a small fraction of this would be attributed to production enabled by well stimulation. To put this number in context, the onshore water disposal volume in Santa Barbara and Ventura counties in 2013 was about 10 million m^3 (63 million barrels).

The estimated maximum volume of water disposal in the offshore Los Angeles Basin in 2013 is about 1 million m^3 (6 million barrels), including facilities in both federal and state waters. More than 0.8 million m^3 (5 million barrels) of this water disposal is for the Beta field, which has no record of hydraulic fracturing. To put this number in context, the onshore water disposal volume in Los Angeles and Orange counties in 2013 was about 3.5 million m^3 (22 million barrels).

The results indicate that the volume of water injected into water disposal wells offshore associated with well-stimulation-enabled production is much smaller than the volume of water disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, the hazard of induced seismicity caused by offshore produced water disposal linked with well-stimulation-enabled production is expected to be significantly lower than the hazard of induced seismicity associated with water disposal associated with onshore oil and gas production in these same locations.

2.7.4. Data Gaps

Data gaps have been identified in several areas throughout this report and are summarized here. These can be divided into two areas: well stimulation activities and environmental effects of emissions and discharge.

2.7.4.1. Well Stimulation Activities

Records of federal offshore activities do not include information on well stimulation sufficient to assess this activity. While information on well stimulation exists in records submitted and made available through FOIA document releases, it is extremely difficult to decipher from these documents with confidence what well stimulation activities have been conducted. Records of the activities need to be maintained in a way that can be accessed and understood. Furthermore, other available records indicate that the documentation present in the FOIA documents is extensively incomplete.

The documentation both on a state and federal level is incomplete and inadequate in terms of the compositions and quantities of stimulation fluids used, the depth intervals treated, the composition and quantities of stimulation fluid flowback, and the disposition of this fluid for disposal.

State records of well stimulation are now improved as a result of the Senate Bill 4 reporting requirements. The evaluation of well stimulation activity should be revisited when a more substantial record of treatments has been captured. However, no similar actions have been initiated to improve records of well stimulation in federal waters that are also needed to repair the existing serious gaps in reporting and record keeping.

2.7.4.2. Air Emissions, Ocean Discharge, Injection and Associated Impacts

The impacts of ocean discharge are hampered by the lack of complete records, or even any records for several facilities, concerning the quantities of materials released into the ocean. Separate samplings and monitoring requirements are needed for discharge of well stimulation fluids. If well stimulation fluids are mixed with produced water for discharge, samplings for contaminants are needed when this mixture of wastes is discharged.

An assessment of the discharge of wastewater well stimulation fluids into the ocean should be done. Acute and chronic toxicity data for well stimulation chemicals, as well as chemicals identified in flowback fluids that may be discharged to the ocean, should be determined to provide a basis for understanding environmental effects of this discharge, just as these types of studies have been performed to assess the impacts of produced water discharge. Alternatively, WET testing that clearly includes stimulation fluid chemicals at discharge concentrations could be used to assess and limit impacts.

If well stimulation fluids are injected, the type of injection needs to be documented, i.e., if the injection is into the producing reservoir or into a disposal horizon. For injection into a disposal horizon, the time profile of pressure and injection rate needs to be monitored for evaluation of potential induced seismicity.

Records concerning air emissions are more detailed, complete, and easier to access than wastewater discharge. Nevertheless, the information is still not adequate to quantitatively assess the atmospheric emissions related to well stimulation activities as distinct from air emissions caused by other oil and gas activities.

2.8 Findings, Conclusions, and Recommendations

The findings regarding the conduct of well stimulation treatments for offshore California operations are not substantially different from findings already made for well stimulation activities discussed in Volume I. Hydraulic fracture stimulations at platforms in federal offshore waters have used small injection volumes, whereas the bulk of the activity at THUMS islands close to Los Angeles uses larger treatment volumes similar to onshore California stimulations. Matrix acidizing treatment volumes are even more poorly documented than hydraulic fracturing, but appear to use significantly smaller treatment volumes than hydraulic fracturing; however, they also appear to be used more frequently.

The potential role of hydraulic fracturing in causing leakage from the subsurface is complex, but fracturing from the reservoir to the seafloor is highly unlikely in most cases, because the depths of the reservoirs exceed the maximum potential hydraulic fracture heights that have been observed. However, hydraulic fracturing does involve the temporary use of high pressures in the well. Given the uncertainty surrounding the effects of this pressure on well integrity and potential leakage, precautions as recommended in Appendix D of Volume II should be considered, including injection of hydraulic fracturing fluids through protective tubing and shutting in offset wells within the zone of pressurization of a hydraulic fracturing treatment.

The effects of produced water have been shown to have some sublethal impacts on reproductive behavior and possibly on the overall health of some species. However, studies of the fish populations around California offshore facilities appear to indicate that adverse affects are offset by the increased habitat afforded by the offshore oil and gas facilities. Contamination studies suggest that contaminant exposure levels, presumably as a result of the level of dilution of contaminants discharged, have remained below levels that result in significant adverse impacts. While some level of adverse impacts are likely as a result of wastewater discharge in general, these appear to be subtle relative to the positive effects of habitat on fish populations associated with offshore oil and gas facilities.

The requirements for TCW wastes discharged without mixing with produced water should be reconsidered. For example, the WET test requirements under NPDES that are applicable to produced water (and produced water mixed with TCW wastes) should be considered for TCW discharged on its own. Furthermore, WET testing should be performed when stimulation fluid discharge occurs. Data collection and records concerning well stimulation should be improved for stimulations conducted in federal waters to at least match the requirements of Senate Bill 4. When representative data become available, an assessment of ocean discharge should be conducted and, based on these results, the necessity of alternatives to ocean disposal for well stimulation flowback should be considered.

Criteria pollutants emitted by offshore oil and gas production facilities have been found to be a small fraction of total emissions in the associated air basins. Well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total criteria pollutants emitted by offshore oil and gas production. Therefore, the impacts to the total air emissions are believed to be small. Because of distances between offshore oil and gas production and local populations, toxic air emissions from the facilities in federal waters should have minor to negligible public health effects. But facilities in state waters may have somewhat greater impact because of closer proximity to population. The impacts of toxic air emissions are expected to be low with respect to public safety, but may be of more concern for worker safety. GHG emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations. The associated GHG impact relative to benefits of usable energy produced from these operations is not exceptional. GHG emissions linked to well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total.

The results indicate that the volume of water injected into water disposal wells offshore associated with well-stimulation-enabled production is much smaller than the volume of water disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, the hazard of induced seismicity caused by offshore produced-water disposal linked with well-stimulation-enabled production is expected to be significantly lower than the hazard of induced seismicity associated with water disposal related to onshore oil and gas production in these same locations.

2.9. Acknowledgements

The authors would like to thank Rohit Salve and Regina Linville for their input during the development of this case study.

2.10. References

Adams, M.V. (1969), History of Well No. A-21, Lease OCS P-0241, Appendix A. In: Geology, Petroleum Development, and Seismicity of the Santa Barbara Channel Region, California, Geologic Survey Professional Paper 679, USGS.

Adams, M.V. (1972), Regulation and Supervision of Outer Continental Shelf Operations on the Pacific Coast, Paper Number OTC 1713, Fourth Annual Offshore Technology Conference, Houston, TX, May 1-3, 1972. pp. II-835 - II-843.

Ahuja, M.P., J.C. McGufee, and S.A. Poulter (2003), Decommissioning of Belmont Island, an Offshore Oil Platform. SPE 83486, SPE Western Regional/AAPG Pacific Section Joint Meeting, Long Beach, CA, May 19-24, 2003.

API (American Petroleum Institute) (2013), Offshore Hydraulic Fracturing.

Armstrong, N.R., and A.M. Evans (2011), Extended Reach Drilling Offshore California. Extending Capabilities and Improving Performance. SPE/IADC 140265, SPE/IADC Drilling Conference and Exhibition, Amsterdam, The Netherlands, March 1-3, 2011, 13 pp.

ASTM (American Society for Testing and Materials) (2012), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), ASTM D287 - 12b.

Baake, T., J. Klungsøyr, and S. Sanni (2003), Environmental Impacts of Produced Water and Drilling Waste Discharges from the Norwegian Offshore Petroleum Industry. Marine Environmental Research, 92, 154-169.

Balk, L., K. Hylland, T. Hansson, M.H.G. Berntssen, J. Beyer, G. Jonsson, A. Melbye, M. Grung, B.E. Torstensen, J.F. Børseth, J. Skarphedinsdottir, and J. Klungsøyr (2011), Biomarkers in Natural Fish Populations Indicate Adverse Biological Effects of Offshore Oil Production, PloS ONE, 6 (5).

Bascom, W., A.J. Mearns, and M.D. Moore (1976), A Biological Survey of Oil Platforms in the Santa Barbara Channel. Journal of Petroleum Technology, November 1976, pp. 1280-1284.

Beyer, L.A. (1995), Los Angeles Basin Province (014). In: National Assessment of United States Oil and Gas Resources--Results, Methodology, and Supporting Data, Gautier, D.L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., ed., 1995: U.S. Geological Survey Digital Data Series DDS-30, 19 pp.

BOEM (Bureau of Ocean Energy Management) (2012), Field Reserve Estimate Summary as of December 2012.

BOEM (Bureau of Ocean Energy Management) (2013), Field Reserve Estimate Summary as of December 2013.

BOEM (Bureau of Ocean Energy Management) (2014a), 2011 National Assessment of Oil and Gas Resources: Assessment of the Pacific Outer Continental Shelf Region. OCS Report BOEM 2014-667, K.A. Piper, Editor, C.O. Ojukwu, Co-Editor.

BOEM (Bureau of Ocean Energy Management) (2014b), http://www.boem.gov/pacific-ocs-map/.

BOEM (Bureau of Ocean Energy Management) (2015a), Status of Leases and Qualified Companies Pacific OCS Region, January 2015.

BOEM (Bureau of Ocean Energy Management) (2015b), http://www.boem.gov/BOEM-Newsroom/Offshore-Stats-and-Facts/Pacific-Region/Pacific-Platform-Operators.aspx.

BOEM (Bureau of Ocean Energy Management) (2015c), Pacific Wells.zip, http://www.boem.gov/Oil-and-Gas-Energy-Program/Mapping-and-Data/Pacific.aspx.

BOEM (Bureau of Ocean Energy Management) (2015d), Pacific Production Information and Data Available in ASCII Files for Downloading, http://www.data.boem.gov/homepg/data_center/production/PacificFreeProd.asp.

BOEM (Bureau of Ocean Energy Management) (2015e), Spills - Statistics and Summaries 1964-1995 (2,100 Gallons), http://www.boem.gov/Environmental-Stewardship/Environmental-Assessment/Oil-Spill-Modeling/spills-1964-1995.aspx#1968.

BSEE (Bureau of Safety and Environmental Enforcement) (2015), BSEE FOIA Reading Room, http://www.bsee.gov/About-BSEE/FOIA/BSEE-FOIA-Reading-Room/

California Coastal Sanctuary Act (1994), California Public Resources Code Section 6240-6244, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=prc&group=06001-07000&file=6240-6244.

California Public Resources Code Section 6873, http://law.onecle.com/california/public-resources/6873.html.

CARB (California Air Resources Board) (2015a), Facilities Search Engine, http://www.arb.ca.gov/app/emsinv/facinfo/facinfo.php.

CARB (California Air Resources Board) (2015b), Greenhouse Gas Emission Inventory—Query Tool for years 2000 to 2012 (7th Edition), http://www.arb.ca.gov/app/ghg/2000_2012/ghg_sector.php.

Cardno ENTRIX (2012), Hydraulic Fracturing Study—PXP Inglewood Oil Field. http://www.scribd.com/doc/109624423/Hydraulic-Fracturing-Study-Inglewood-Field10102012.

Carlisle, J.G., JR., C.H. Turner, and E.E. Ebert (1964), Artificial Habitat in the Marine Environment. Fish Bulletin, 124, The Resources Agency of California, Department of Fish and Game, http://www.oac.cdlib.org/view?docId=kt929006q1&brand=oac4&doc.view=entire_text.

Carpenter, R. (2011), Raid Force Trains To Seize Offshore Oil Platform, Marines, http://www.11thmeu.marines.mil/News/NewsArticleDisplay/tabid/2683/Article/533616/raid-force-trains-to-seize-offshore-oil-platform.aspx.

CCC (California Coastal Commission) (2013), Staff Report: Regular Calendar, W13a, Consistency Determination No.: CD-001-13, 89 pp.

Chiang, J. (2009), Chiang Issues Statement on New Tranquillion Ridge Offshore Oil Development, PR09:006, California State Controllers Office, Sacramento, CA. http://www.sco.ca.gov/eo_pressrel_5499.html

Claisse J.T., D.J. Pondella, M. Love, L.A. Zahn, C.M. Williams, J.P. Williams, and A.S. Bull, (2014), Oil Platforms Off California Are Among the Most Productive Marine Fish Habitats Globally. PNAS, 111 (43), 15462–15467, www.pnas.org/cgi/doi/10.1073/pnas.1411477111.

CSLC (California State Lands Commission) (1999), http://www.slc.ca.gov/division_pages/mrm/rigs_to_reef/oilfacilities.html

CSLC (California State Lands Commission) (2008), Safety and Oil Spill Prevention Audit, Rincon Island Limited Partnership, Mineral Resources Management Division.

CSLC (California State Lands Commission) (2009), Safety and Oil Spill Prevention Audit, Aera Onshore, Offshore, Aera Energy LLC, Oil Company, Mineral Resources Management Division.

CSLC (California State Lands Commission) (2010a), Safety and Oil Spill Prevention Audit, Platform Esther, Dos Cuadras Offshore Resources (DCOR), Mineral Resources Management Division.

CSLC (California State Lands Commission) (2010b), Safety and Oil Spill Prevention Audit, DCOR Platform Eva, DCOR LLC, Oil Company, Mineral Resources Management Division.

CSLC (California State Lands Commission) (2012), Safety and Oil Spill Prevention Audit, Platform Holly, Veneco, Inc., Mineral Resources Management Division.

CSLC (California State Lands Commission) (2013), Safety and Oil Spill Prevention Audit, Long Beach Unit, Oxy Long Beach, Inc. (OLBI), Mineral Resources Management Division.

Clean Water Act (1972), Clean Water Act, Section 403 Ocean Discharge Criteria, http://water.epa.gov/lawsregs/guidance/wetlands/sec403.cfm.

Dibblee, Jr., T.W. (1988), Geology of the Ventura Basin Area. In: Ventura Basin: Geologic Introduction and Field Trip Guidebook, M.H. Link (ed), AAPG Pacific Section, 6-17.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (1982), California Oil & Gas Fields, Volume III – Northern California, California Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (1992), California Oil & Gas Fields, Volume II – Southern, Central Coastal, and Offshore California Oil and Gas Fields, California Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (1998), California Oil & Gas Fields, Volume I—Central California, California Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2010), 2009 Annual Report of the State Oil and Gas Supervisor, Publication No. PR06, Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2011), 2010 Preliminary Report of California Oil and Gas Production Statistics, Publication No. PR03, Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2012), 2011 Preliminary Report of California Oil and Gas Production Statistics, Publication No. PR03, Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2013), 2012 Preliminary Report of California Oil and Gas Production Statistics, Publication No. PR03, Department of Conservation, California.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2014a), 2013 Preliminary Report of California Oil and Gas Production Statistics, Publication No. PR03, Department of Conservation, California.

DOGGR (Division of Oil, Gas and Geothermal Resources) (2014b), SB 4 Well Stimulation Treatment Regulations, Sacramento, CA, 14 pp. OAL Reference Number: Z-2013-1105-01, http://www.conservation.ca.gov/index/Documents/Oct.%209,%202014%20final%202nd%20revised%20SB%204%20WST%20 regulations.pdf.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2014c), 20140507_CAWellStimulationPublicDisclosureReport.xls, http://www.conservation.ca.gov/dog/Pages/WellStimulation.aspx, Well Stimulation Disclosures.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2014d), http://maps.conservation.ca.gov/doggr/iwst_index.html.

DOGGR (Division of Oil, Gas, and Geothermal Energy) (2015), Online Production and Injection Query for State of California, http://opi.consrv.ca.gov/opi/opi.dll/Search?UsrP_ID=100175545&FormStack=Main%2CField&Fld__Code=849&Action=%3C%3C+Back++&PriorState=Encoded%3DTrue.Engle, D.L. (2006), Assessment of Coastal Water Resources and Watershed Conditions at Channel Islands National Park, California, Technical Report NPS/NRWRD/NRTR-2006/354, National Park Service, U.S. Department of the Interior, Water Resources Division.

FR (Federal Register) (1993), 58 FR 12454, Oil and Gas Extraction Point Source Category; Offshore Subcategory Effluent Limitations Guidelines and New Source Performance Standards, Environmental Protection Agency, March 4, 1993, 58 (41).

Frame, R.G. (1960), California Offshore Petroleum Development in Summary of Operations, California Oil Fields, Forty-Sixth Annual Report of the State Oil and Gas Supervisor, Department of Natural Resources, Division of Oil and Gas, 46 (2), 5-46.

Gale, R.W., M.J. Tanner, M.S. Love, M.M. Nishimoto, and D.M. Schroeder (2012), Comparison of Concentrations and Profiles of Polycyclic Aromatic Hydrocarbon Metabolites in Bile of Fishes from Offshore Oil Platforms and Natural Reefs along the California Coast, Open-File Report 2012–1248, U.S. Department of the Interior, U.S. Geological Survey.

Gale, R.W., M.J. Tanner, M.S. Love, M.M. Nishimoto, and D.M. Schroeder (2013), Comparison of Aliphatic Hydrocarbons, Polycyclic Aromatic Hydrocarbons, Polychlorinated Biphenyls, Polybrominated Diphenylethers, and Organochlorine Pesticides in Pacific sanddab (Citharichthys sordidus) from Offshore Oil Platforms and Natural Reefs along the California Coast, Open-File Report 2013–1046, U.S. Department of the Interior, U.S. Geological Survey.

Goleta (2015), Current Oil and Gas Operations Within and Near Goleta, Platform Holly, http://www.cityofgoleta.org/index.aspx?page=1042.

Grosbard, A. (2002), Treadwell Wharf in the Summerland, California Oil Field: The First Sea Wells in Petroleum Exploration. Oil-Industry History, 3 (1).

Hauser, R.L., and W.F. Guerard (1993), A History of Oil and Gas Well Blowouts in California, 1950-1990, Publication Number TR43, California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Sacramento, CA.

Holditch, S.A. (2006), Tight Gas Sands. J. Pet. Technol., 58(6), 86–94.

Kalfayan, L.J. (2008), Production Enhancement with Acid Stimulation. M. Patterson, ed., PennWell Corporation.

Keller, M.A. (1995), Ventura Basin Province (13). In: 1995 National Assessment of United States Oil and Gas Resources; Results, Methodology, and Supporting Data, D.L Gautier, G.L. Dolton, K.I. Takahashi, and K.L. Varnes (eds), U.S. Geological Survey Data Series 30, 13 pp.

King, G.E. (2012), Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and O. In: SPE 152596, SPE Hydraulic Fracturing Technology Conference, Society of Petroleum Engineers, Woodlands, TX.

Krause, P.R., C.W. Osenberg, and R.J. Schmitt (1992), Effects of Produced Water on Early Life Stages of a Sea Urchin: Stage-Specific Responses and Delayed Expression. In: Produced Water: Technological/Environmental Issues and Solutions, J.P. Ray and F.R. Englehardt (eds), , Plenum Press, New York, pp. 431-444.

Love, M.S., D.M. Schroeder, and M.M. Nishimoto (2003), The Ecological Role of Oil and Gas Production Platforms and Natural Outcrops on Fishes in Southern and Central California: A Synthesis of Information. OCS Study, MMS 2003-032.

Love, M.S., D.M. Schroeder, and W.H. Lenarz (2005), Distribution of Bocaccio (Sebastes Paucispinis) and Cowcod (Sebastes Levis) around Oil Platforms and Natural Outcrops off California with Implications for Larval Production. Bulletin of Marine Science, 77 (3), 397–408.

Love, M.S., and S.R. Goldberg (2009), A Histological Examination of the Ovaries of Pacific Sanddab, Citharichthys sordidus, Captured at Two Oil Platforms and Two Natural Sites in the Southern California Bight. Bulletin of the Southern California Academy of Sciences, 108 (2), Article 1, http://scholar.oxy.edu/scas/vol108/iss2/1.

Love, M.S., M.K. Saiki, T.W. May, and J.L. Yee (2013), Whole-body Concentrations of Elements in Three Fish Species from Offshore Oil Platforms and Natural Areas in the Southern California Bight, USA. Bulletin of Marine Science. 89(3):717–734, http://dx.doi.org/10.5343/bms.2012.1078.

Lyon, G.S., and E.D. Stein (2010), Effluent discharges from offshore oil platforms to the outer continental shelf of southern California in 2005. In: Southern California Coastal Water Research Project 2010 Annual Report, S.B. Weisberg and K. Miller (eds.), Southern California Coastal Water Research Project. Costa Mesa, CA, pp. 29-43.

Martin, C.J.B, and C.G. Lowe (2010), Assemblage Structure of Fish at Offshore Petroleum Platforms on the San Pedro Shelf of Southern California. Marine and Coastal Fisheries: Dynamics, Management, and Ecosystem Science, 2 (1), 180-194, DOI: 10.1577/C09-037.1.

McCulloh, T.H. (1969), Geologic Characteristics of the Dos Cuadras Offshore Oil Field. In: Geology, Petroleum Development, and Seismicity of the Santa Barbara Channel Region, California, Geologic Survey Professional Paper 679, USGS.

McGuffee, C. (2002), ExxonMobil – Belmont Island Decommissioning Project, Presentation to the California State Lands Commission, http://www.slc.ca.gov/Division_pages/MFD/Prevention_First/Documents/2002/Presentation%20by%20Cris%20McGuffee.pdf.

MMS (Minerals Management Service) (1993), Estimated Oil and Gas Reserves Pacific Outer Continental Shelf, OCS Report MMS 94-0008.

MMS (Minerals Management Service) (1994), Estimated Oil and Gas Reserves Pacific Outer Continental Shelf, OCS Report MMS 94-0059.

MMS (Minerals Management Service) (2001), Delineation Drilling Activities in Federal Waters Offshore Santa Barbara County, California, OCS EIS/EA, MMS-2001-046, U.S. Department of the Interior, Minerals Management Service, Pacific Outer Continental Shelf Region.

MMS (Minerals Management Service) (2007), Estimated Oil and Gas Reserves Pacific Outer Continental Shelf, OCS Report, MMS 2007-012, U.S. Department of the Interior, Minerals Management Service, Pacific Outer Continental Shelf Region.

Nagle, H.E., and E.S. Parker (1971), Future Oil and Gas Potential of Onshore Ventura Basin, California. In: Future Petroleum Provinces of the United States—Their Geology and Potential, Volume 1, I.H. Cram (ed), AAPG Memoir 15, 254-297.

NOAA (National Oceanic and Atmospheric Administration) (1992), Oil Spill Case Histories 1967-1991, Summaries of Significant U.S. and International Spills. Report Number HMRAD 92-11, NOAA Hazardous Materials Response and Assessment Division, Seattle, WA.

NOAA (National Oceanic and Atmospheric Administration) (2015), NOAA Photo Library, http://www.photolib.noaa.gov/htmls/line2969.htm.

NPC (National Petroleum Council) (2011), Subsea Drilling, Well Operations and Completions, Paper #2-11, Offshore Operations Subgroup of the Operations & Environment Task Group, NPC North American Resource Development Study, http://www.npc.org/Prudent_Development-Topic_Papers/2-11_Subsea_Drilling-Well_Ops-Completions_Paper.pdf.

Osenberg, C.W., R.J. Schmitt, S.J. Holbrook, and D. Canestro (1992), Spatial scale of ecological effects associated with an open coast discharge of produced water. In: Produced Water: Technological/Environmental Issues and Solutions, Plenum Press, New York, pp. 387-402.

Patton, B., F. Pitts, T. Goeres, and G. Hertfelder (2003), Matrix Acidizing Case Studies for the Point Arguello Field. In: SPE 83490, Proceedings of SPE Western Regional/AAPG Pacific Section Joint Meeting, Society of Petroleum Engineers.

Raimondi, P., and A. Boxshall (2002), Effects of Produced Water on Complex Behavior Traits of Invertebrate Larvae. OCS Study MMS 2002-050, U.S. Department of the Interior, Minerals Management Service, Pacific OCS Region, 38 pp.

Rowe, G., R. Hurkmans, and N. Jones (2004), Unlocking the Monterey Shale Potential at Elk Hills: A Case Study. In: Proceedings of SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, Society of Petroleum Engineers.

Sanchez, M., and R. Tibbles (2007), Frac Packing: Fracturing for Sand Control. Middle East Asia Reserv. Rev., 8, 36–49.

Saniere, A. (2011), Definitions and Specificities. In: Heavy Crude Oils, From Geology to Upgrading—An Overview, Editions Technip, A.-Y. Huc, editor, Paris. ISBN: 978-2-7108-0890-9.

Santa Barbara (2011), Draft Environmental Impact Report for the Ellwood Pipeline Company Line 96 Modification Project, State Clearinghouse No. 2009111034, Santa Barbara County EIR No. 09EIR-00000-00005, Lead Agency: County of Santa Barbara.

Santa Barbara (2015a), County of Santa Barbara Planning and Development Energy Division, http://www.sbcountyplanning.org/energy/projects/Chevron_4H.asp.

Santa Barbara (2015b), Blowout at Union Oil's Platform A, http://www.sbcountyplanning.org/energy/information/1969blowout.asp.

Sattarin, M., H. Modarresi, M. Bayat, and M. Teymori (2007), New Viscosity Correlations for Dead Crude Oils. Petroleum & Coal, 49 (2),33-39.

Schempf, F.J. (2004), Special Anniversary - The History of Offshore: Developing the E&P Infrastructure, Offshore, http://www.offshore-mag.com/articles/print/volume-64/issue-1/news/special-report/special-anniversary-the-history-of-offshore-developing-the-ep-infrastructure.html.

Shah, M. (2013), Guidelines on Selection and Design of Cooling Options for Offshore Applications, PetroMin, January/February 2013, http://www.petromin.safan.com/mag/pjanfeb13/t58.pdf.

Silcox, W.H., J.A. Bodine, G.E. Burns, C.B. Reeds, D.L. Wilson, E.R. Sauve (1987), Offshore Operations. In: Petroleum Engineering Handbook, H.B. Bradley, Editor in Chief (Associate Editors: F.W. Gipson, A.S. Odeh, P.S. Sizer, M. Mortada, L.L. Raymer, G.L. Smith), Society of Petroleum Engineers, Richarson TX, USA.

Sutherland Asbill & Brennan LLP (2008), Congress Allows Moratorium on Offshore Drilling to Expire, http://www.lexology.com/library/detail.aspx?g=4cb13ed2-aed3-4d0f-8b85-59e23a8ed659.

The Atlantic Photo (2014), Aerial View of Grissom Island. http://www.theatlantic.com/photo/2014/08/the-urban-oil-fields-of-los-angeles/100799/#img13

The Resources Agency of California (1971), The Offshore Petroleum Resource, Department of Conservation, CA.

University of California, Santa Barbara (2011), April 18, 2011 - Earth Day: A Retrospective, http://www.geog.ucsb.edu/events/department-news/846/earth-day-a-retrospective/.

U.S. EPA (Environmental Protection Agency) (1993), Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-93-003, Office of Water, 407 pp.

U.S. EPA (Environmental Protection Agency) (1995), Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, 821-R-95-009, Office of Water, 654 pp.

U.S. EPA (Environmental Protection Agency) (1996), Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-96-023, Office of Water, 640 pp.

U.S. EPA (Environmental Protection Agency) (2013a), Authorization to Discharge Under the National Pollutant Discharge Elimination System for Oil and Gas Exploration, Development, and Production Facilities, General Permit No. CAG280000.

U.S. EPA (Environmental Protection Agency) (2013b), Addendum to Fact Sheet, Final National Pollutant Discharge Elimination System ("NPDES") General Permit No. CAG280000 for Offshore Oil and Gas Exploration, Development and Production Operations off Southern California.

U.S. EPA (Environmental Protection Agency) (2015a), Permit Compliance System (PCS) and Integrated Compliance Information System (ICIS) databases search, http://www.epa.gov/enviro/facts/pcs-icis/search.html.

U.S. EPA (Environmental Protection Agency) (2015b), EPA Flight, Facility Level Information on Greenhouse Gasses Tool, http://ghgdata.epa.gov/ghgp/main.do.

U.S. EPA (Environmental Protection Agency) (2015c), ECOTOX Database, http://cfpub.epa.gov/ecotox/.

U.S. House of Representatives (2011), Obama Administration Imposes Five-Year Drilling Ban on Majority of Offshore Areas, US House of Representatives, Natural Resources Committee, Chairman Doc Hastings, November 8, 2011, http://naturalresources.house.gov/news/documentsingle.aspx?DocumentID=267985.

Weaver, D.K. (1937), Pumping Slant Holes at Huntington Beach, California, Drilling and Production Practice, API-37-138, American Petroleum Institute, New York, New York. pp. 138-147.

Wentworth, A. (1998), Huntington Beach, A Bicentennial Community, City of Huntington Beach Miscellaneous Historical Data, http://www.huntingtonbeachca.gov/files/users/library/complete/071108-2.pdf.

Wikimedia Commons (2015), http://commons.wikimedia.org/wiki/File:RinconIslandCauseway.jpg.

Wilkinson, E.R. (1972), California Offshore Oil and Gas Seeps, California Division of Oil and Gas, Sacramento, CA., 11 p.

Wright, T.L. (1991), Structural Geology and Tectonic Evolution of the Los Angeles Basin, California. In: Active Margin Basins, K.T. Biddle (ed), AAPG Memoir 52, 35-134.

Yerkes, R.F., H.C. Wagner, and K.A. Yenne (1969), Petroleum Development in the Region of the Santa Barbara Channel. In: Geology, Petroleum Development, and Seismicity of the Santa Barbara Channel Region, California, Geologic Survey Professional Paper 679, USGS.